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SIMULATION OF MICROGRID PROTECTION WITH SYNCHRONOUS AND INVERTER-BASED GENERATION

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ABSTRACT

Salena Bantz: Simulation of microgrid protection with synchronous and inverter-based generation
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Microgrids might enable environmental and economic improvements to the electric grid. The introduction of renewable energy sources to the power supply has opened new doors for a cleaner power system and novel grid structure changes such as microgrids. Microgrids are local power networks that can operate in grid-connected or islanded mode. One of the main challenges of microgrids is reliable and accurate protection. Intermittent generation and multiple modes of operation might change fault current behaviour drastically. Protection schemes must always function regardless of network topology, mode of operation, or generation level. Simulation case studies are helpful to test microgrid protection schemes for different microgrid states. In this thesis work, a microgrid is modelled to the needed extent for protection studies using PSCAD software. Protection use cases are simulated with PSCAD to demonstrate protection considerations for microgrids operating in grid-connected and islanded modes.

Keywords: microgrids, protection, distributed power system, distributed energy

The originality of this thesis has been checked using the Turnitin OriginalityCheck service.

PREFACE

I am extremely grateful to my thesis advisors and professors over the last two years for their help and encouragement. I am thankful to Professor Pertti Järventausta and Lasse Peltonen for their guidance and assistance. I also thank my friends and family for their love and support.

Tampere, 28 April 2023

Salena Bantz

CONTENTS

LIST OF SYMBOLS AND ABBREVIATIONS

ANM	Active Network Management
AVC	Active Voltage Control
BESS	Battery Energy Storage System
DER	Distributed Energy Resources
DG	Distributed Generation
DSO	Distribution Systems Operator
EF	Earth Fault
EMT	Electromagnetic transient
EV	Electric Vehicle
FACTS	Flexible Alternating Current Transmission System
FCL	Fault Current Limiter
FRT	Fault Ride Through
HIF	High Impedance Fault
HIL	Hardware in the Loop
IIDG	Inverter-interfaced generation
ICT	Information and Communication Technology
MMO	Multi-master Operation
OC	Overcurrent
PCC	Point of Common Coupling
PI	Proportional Integrator
PLL	Phase-Locked-Loop
PWM	Pulse Width Modulation
SG	Synchronous Generator
SMO	Single-master Operation
THD	Total Harmonic Distortion
TMS	Time Multiplier Setting
VSI	Voltage Source Inverter

The abbreviations and symbols used in the thesis are collected into a list in alphabetical order.

1. INTRODUCTION

Energy visionaries look to the year 2050 as the realization of a clean and reliable energy system built upon Smart Grid technology [1]. Environmental concerns, increasing power demand, and rising energy prices demonstrate the need for a global energy transition. Decarbonizing generation to prevent climate change has introduced renewable energy sources to the power supply. The most ambitious futurists see a 100% renewable energy society working in coordination across the power, heat, and transport sectors. The benefits of 100% renewable energy systems include reduced air pollution, increase employment opportunities, and higher energy security [2].

1.1 Energy transition

The concept of a microgrid could be a major building block capable of revolutionizing the existing grid. A microgrid is a localized power grid that can work in grid-connected mode or islanded mode. It is viewed as one of the best ways to integrate and maximize renewable generation in the power supply.

A microgrid technique proposes several challenges to the large-scale power system. Distributed generation (DG) is often from renewable sources, such as wind and solar, that work intermittently and are connected to the grid through an inverter. Power systems with a high amount of inverter-interfaced distributed generation (IIDG) operate in a fundamentally different way than the traditional power grid. Unlike synchronous generation (SG), IIDG does not offer any mechanical system inertia for grid stability. Additionally, IIDG sources are often variable and introduce challenges to power continuity and quality such as voltage flicker, voltage dips, and harmonics [3].

There are several ways to classify a microgrid such as according to inverter connection, mode of operation, generation sources, size, or scenario. Microgrid control and protection solutions depend significantly on the level of IIDG production; for this reason, one microgrid categorisation approach is according to the generation connection:

- Category 1: Exclusively SG production
- Category 2: Partially SG production and partially IIDG production
- Category 3: Exclusively IIDG production

The scope of this thesis focuses on Category 2 microgrids where the generation is partially SG and partially IIDG. Futurists proceeding towards a perfect 100% renewable energy society often disregard the challenges of renewable integration on system security, stability, costs, and reliability. Research and development of microgrid solutions are necessary to overcome these challenges and quickly realize the energy transition.

Among the many technical challenges of microgrids, protection is often of the most concern. In some cases, effective microgrid protection is the main limiting factor to the amount of distributed energy resources (DER) allowed in the generation mix. IIDG often does not contribute substantially to the fault current which can lead to protection system failure. Protection systems in microgrids must adapt to multiple operational modes and more dynamic fault current situations than previous power grid designs. Example protection challenges include blinding, sympathetic tripping, and loss-of-mains detection. New design approaches for protection schemes could make microgrids a more reliable option for the energy transition.

Power system simulations, especially in recent times, have become essential for microgrid design, analysis, operation, and planning. Detailed simulations are necessary to ensure that protection systems can operate in a variety of microgrid topologies and generation scenarios.

1.2 Research objectives

The purpose of this thesis is to demonstrate protection principles for Category 2 AC microgrids. A microgrid with SG and IIDG is designed, modelled, and tested for protection studies. The protection studies of this thesis focus on protection for internal low-impedance microgrid faults. This thesis investigates the following questions:

- What are the protection challenges for AC microgrids with IIDG?
- How can the system dynamics of an AC microgrid with IIDG be modelled for protection studies?
- What is the fault transient response for IIDG microgrids in grid-connected mode?
- What is the fault transient response for IIDG microgrids in islanded mode?
- How do DG sources supply fault current?

The first chapter introduces the purpose and scope of the thesis. The second chapter is a literature review on microgrids as part of the Smart Grid. The third chapter is a literature review on microgrid protection. The fourth chapter describes the microgrid PSCAD model design including the voltage source inverter (VSI) design for the battery energy storage system (BESS). The fifth chapter shows the protection testing results for the grid-connected microgrid. The sixth chapter shows the protection testing results for the islanded microgrid. The seventh chapter is a discussion of the results, and the eighth chapter is the conclusion.

2. MICROGRIDS AS PART OF SMART GRID

Engineers worldwide are developing the Smart Grid to advance the global energy transition. The purpose of the Smart Grid is to make the electric grid more controllable, efficient, flexible, and clean without compromising a reliable power supply. The future grid will most likely have considerable changes in architecture, control, communication, and energy management.

2.1 Smart Grid definition

The Smart Grid is an "electric power network that is characterized by an efficient and reliable infrastructure with the use of sophisticated and modern control, communication, sensing and measurement techniques" [4]. The goals of the Smart Grid are to include consumers in power system operation, increase renewable energy penetration, decrease fossil fuel dependency, decrease complete blackouts, increase power system capacity, reduce grid restoration time, and implement peak shaving [5].

A microgrid is a small-scale power system, with local DG sources and loads, that operates connected to the main grid or islanded [6]. Microgrid architecture can operate under different combinations of generation, storage, and loads; some designs have more complex power flow and control strategies compared to traditional electric grid principles [7]. Microgrids will be an important part of the Smart Grid revolution because the concept enables a shift from centralized generation to distributed generation. Microgrids might advance flexibility, reliability, cleaner operation, active network management (ANM), and active voltage control (AVC). Microgrids are a vital part of implementing Smart Grid goals such as network restoration, smart measurements, advanced communication, and higher levels of DG. An example microgrid is shown in Fig. 1.

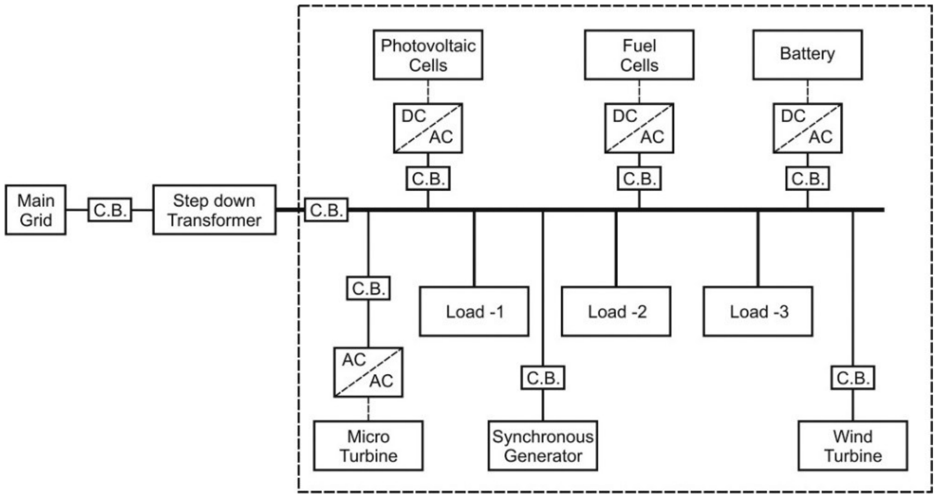


Figure 1. *Diagram of example microgrid [8]*

A microgrid is a controllable part of the power system [8]. The microgrid can operate in connection with the main grid, or independently when the circuit breaker is opened at the point of common coupling (PCC) and the microgrid becomes islanded. Often microgrids are the mechanism by which more DER are integrated into the power supply; DER in microgrids can be from solar power plants, fuel cells, BESS, micro-turbines, SG, or wind farms.

2.2 Microgrid benefits

Microgrids are a way for the grid to become more efficient, flexible, clean, and reliable. An increase in efficiency produces economic advantages that lower energy costs. Net efficiency for the entire power system depends on the planned placement and size of the DER. Strategic placement of DER at high-demand nodes can improve efficiency by reducing line losses. Incorporating market forces through dynamic pricing and load control also makes the use of electricity more efficient and flexible. Time-of-use pricing puts electricity prices higher during periods of high demand, which encourages customers to shift their consumption to other periods. Demand response can prevent inefficient practices such as load-shedding and generation curtailment.

Flexible resources seen in microgrids include DG units, BESS, electric vehicles (EVs), and controllable loads. Controllable resources respond to power system changes quickly and can possibly lower total system costs [9]. Energy storage systems are increasing in presence because of their potential to improve microgrid flexibility [10]. Flexibility services can also be expanded through the development of an energy market platform. Such a platform, if operating in real-time, could facilitate energy trading between customers, market actors, and grid operators.

Higher integration of DER into the energy supply is a strong motivating factor for the Smart Grid. Depending on the type and location added, DER in a microgrid can create a cleaner grid with less pollution. DG does not necessarily mean renewable energy, but instead, it refers to any form of localized generation, such as PV, wind turbines, small diesel generators, and fuel cells.

Microgrids have the potential to improve grid reliability through improved network restoration. In controlled islanding, a microgrid can reduce interruption durations and reduce the failure area. Microgrids can also offer congestion services during the process of network restoration [11].

2.3 Microgrid operational principles

A microgrid works in two operational modes. Microgrid designs have power grid requirements such as power quality, stability, reliability, and protection. New generation sources need controllers that direct the power flow from a whole-system perspective. The operational principles discussed in this section mainly focus on Category 2 microgrids. There is also a part that briefly describes Category 3 microgrids, which is a system with 100% inverter-connected generation.

2.3.1 Two operational modes

Microgrids can operate in grid-connected mode and island mode. In grid-connected mode, there is power flow between the main grid and the microgrid. The main grid establishes frequency and voltage levels. Grid-connected mode is better for microgrid stability because of the properties of the SG moment of inertia of the rotor. SG inertia slows down system-wide frequency deviations. In addition to the grid inertia, SG also supplies large and sustained fault current which helps protection schemes detect faults.

In islanded mode, DER is the only generation available. The absence of large-scale SG in the power supply, along with the fragility of a microgrid being a smaller and more variable system, leads to the necessity of careful approaches to meet power quality, stability, reliability, and protection requirements.

2.3.2 Power quality

Microgrids are required to deliver power within acceptable power quality levels. Common power quality metrics include power factor, limits for voltage and frequency deviations, total harmonic distortion (THD), and voltage and current unbalance tolerance. Inverters operate with power electronics that use high-frequency semiconductor switching devices. Power electronic devices present power quality problems such as harmonics, flicker, and voltage unbalance [12]. Single-phase loads and non-linear loads might further deteriorate power quality.

Power quality concerns must be addressed when planning and operating microgrids. Compensation devices are often necessary to deal with the power quality issues in microgrids [13]. Power quality solutions such as flexible alternating current transmission system (FACTS) devices can be costly to overall microgrid investment. Filtering can be done close to the harmonic source to limit the negative power quality impacts of power electronics.

2.3.3 Stability

Traditional power systems rely on SG for primary frequency control; SG gives mechanical inertia to the grid that supports stability when frequency tends to deviate. High levels of renewable sources in a small-scale power system could make it challenging to balance supply and demand to maintain stability. To ensure stability, an islanded microgrid requires energy management and control to guarantee that supply and demand are balanced.

In the situation of entirely inverter-based microgrids, frequency is no longer functionally defined by the rotational masses of the SG. IIDG can be connected as grid-following by supplying constant power or grid-forming by using reactive power to control frequency and voltage [14]. Robust control strategies for grid-forming inverters are important for improving microgrid system stability issues that come from a shortage of inertia.

2.3.4 Reliability

A key objective for a distribution systems operator (DSO) is to maintain a continuous power supply. In some circumstances, DER added to the power system creates more reliability problems than advantages. Grid planning is important to ensure that adding DERs will not compromise grid reliability. If possible, the placement and size of DERs should be optimized according to reliability indices. Another way for microgrids to improve reliability is through intended islanding. In the case of a utility-side fault, an isolated microgrid can still supply services to the area and reduces the number of affected customers. For an internal microgrid fault, an effective protection system must quickly isolate the faulty area and reduce interruption time and area [14].

2.3.5 Protection

The purposes of a protection scheme are to isolate the faulted part of the grid, minimize system disruption time and area, and avoid damage to people and equipment

[15]. There are several requirements for an effective microgrid protection scheme to include selectivity, sensitivity, and speed. Selectivity is important because the protection system must only clear the faulted feeder. Sensitivity indicates the accuracy of relay pick-up reactions; it can be evaluated by comparing the actual relay tripping behaviour to the relay pick-up curves. Additionally, operational speed should be maximized to protect any equipment from damage due to the high fault current level [14].

In a microgrid, protection principles are not always the same as traditional power systems because of bi-directional power flow, two operational modes, and low IIDG fault current contributions. These differences change the fault current response and often cause protection challenges. Fault current magnitude and direction depends on power generation sources, load state, impedance, configuration, and operational mode. In a microgrid, all of these fault current factors are more highly dynamic; therefore, designing microgrid protection systems that can effectively function with several changing variables can be extremely challenging.

2.4 Microgrid configurations

The concept of a microgrid can be applied in many ways as described in Fig. 2.

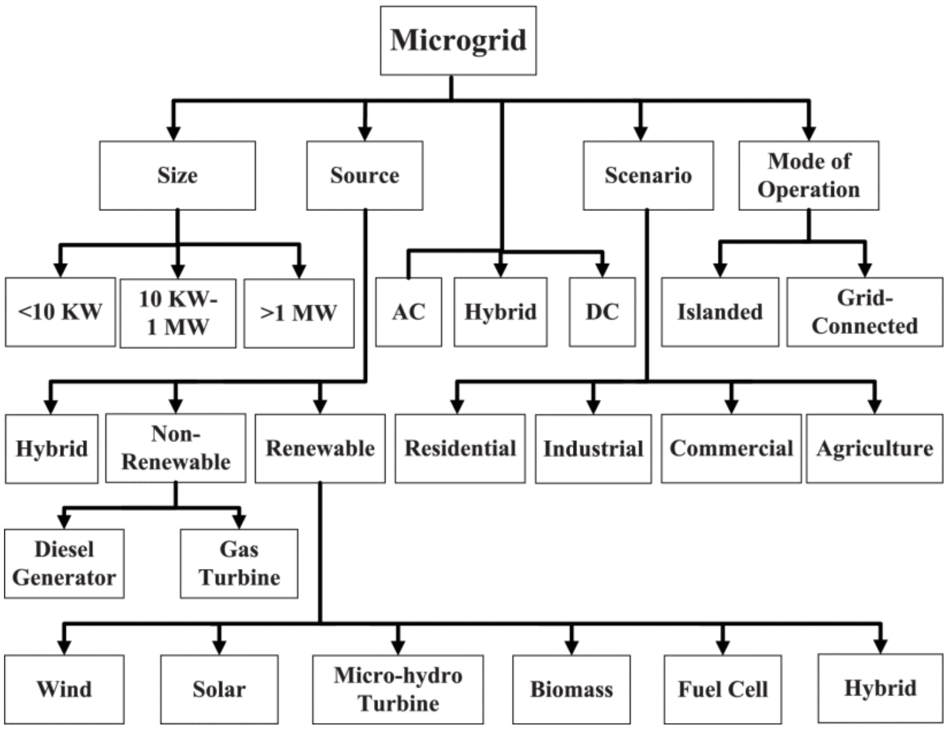


Figure 2. *Flow chart of microgrid types [14]*

Microgrids can be classified according to size, source, scenario, or mode of operation. As explained earlier, microgrids can also be classified according to the inverter connection of the supply. Microgrids can be all inverter-based, all SG-based, or inverter and

SG-based [5]. Microgrids with a large proportion of grid-connected SG is likely to operate well with traditional control and energy management schemes. The proportion of inverter-based DER to normal SG partly defines microgrid behaviour, and the countermeasures necessary, for microgrid stability, power quality, and protection.

2.4.1 Topology

In contrast to the usual radial topology, microgrid topology design is seen as looped, meshed, or mixed. Microgrid topology can be adaptive; changes in DG connection, controllable loads, and peak-demand adjustment allow for a large variety of network states [15]. Network changes are made for load optimization and voltage control. Example actions for topology adjustments include displacement of separation points, structure change by ring closures, and structure change through meshes [16]. The concept of networked microgrids, where topology changes are dynamic and change in real time, is appealing because of the possibility of self-healing networks. Self-healing exists when the microgrid responds to significant disturbances with topology changes to isolate faulty sections and improve overall resilience [17].

Microgrid configuration is important when selecting an appropriate protection scheme because it will influence the fault current flow path. Fault currents depend on the topology of the network. Increased embedded DG will change the fault current flow paths.

The fault current response will depend on the microgrid topology and could become extremely complex, especially compared to the unidirectional radial solution. In a looped microgrid, fault current splits into multiple directions. An upstream protection device could see twice the level of fault current in this configuration. For a mesh topology, the upstream and downstream devices will see the same levels [18].

2.4.2 Grounding strategy

Another configuration factor, especially in the context of AC microgrid protection, is the earth grounding strategy. Grounding configuration for microgrids is an important consideration because grounding will affect fault currents and voltages, equipment safety, power quality, and maintenance cost [19]. Grounding provides a return path for leakage currents. The grounding configurations for LV distribution systems are most commonly TT, IT, or TN. The first letter describes connection of the transformer neutral of the supply source and the second letter describes the frame connection.

For a TT system, the transformer neutral is earthed, and the frame is earthed. The IT system has an unearthed transformer neutral and an earthed frame. A TN system also has the transformer neutral of the supply source earthed; all other conductive parts are connected to the neutral conductor. The three subsystems of TN earthing are TN-C, TN-S, and TN-C-S. The additional letters denote the configuration of the neutral and protective conductors. TN systems are safer for personnel because the touch voltages are reduced compared to TT systems. For protection applications, TN systems are useful for microgrids because they supply higher fault currents than TT and IT earthing [19].

2.5 Microgrids with 100% inverter-based generation

An alternative category of microgrids is Category 3, where all loads and production units are connected to the microgrid by an inverter. A complete absence of SG radically changes the operating principles for this type of microgrid. This section describes the stability, control, and protection differences for 100% inverter-based microgrids.

2.5.1 Stability challenges

In the case of no SG, there are no rotating parts in the microgrid to give physical inertia. Without SG to provide rotational support, the creation of voltage and frequency is now entirely different. In most cases, power system control schemes use frequency as the primary control variable. Zero inertia systems face severe stability problems because frequency and load fluctuations occur more rapidly. A robust control scheme is therefore especially vital to keep generation and consumption matched and prevent system collapse.

Microgrids face stronger consequences from load and generation changes due to the smaller overall system size. Any load or generation change will result in a proportionally higher imbalance. One solution to this problem is to execute load shedding for non-critical loads as an emergency effort to match generation and load [20]. An important part of control performance is an accurate and reliable PLL. In the circumstance of abrupt imbalance from sudden load changes or fault transients, a PLL could struggle to accurately detect large and fast frequency fluctuations.

2.5.2 Grid-forming inverters

One solution to the loss of SG for frequency regulation is the grid-forming inverter control strategy. A VSI can regulate the grid by setting the voltage and frequency. A grid-forming VSI often executes control according to droop control where frequency varies linearly with active power and voltage varies linearly with reactive power. The coordination of multiple VSI can be done through single master operation (SMO) or multi-master operation (MMO). In SMO, one inverter is named the master for setting the voltage and frequency references. All other inverters work according to the PQ strategy. In MMO, there are several inverters working to set voltage and frequency. The power sharing done across the system will happen according to the rated active powers of the inverters [20].

3. MICROGRID PROTECTION

Protection schemes exist to detect and respond to abnormal current, voltage, and frequency events. Protection devices include fuses, relays, and circuit breakers. Relays operate by comparing measurements such as current, voltage, and frequency to threshold protection setting values. Once these thresholds are exceeded, the protection relay will send a tripping signal to the circuit breaker to isolate the faulty section. Protection schemes used for normal power systems do not always function properly for microgrids. Changes such as more complex topologies and intermittent generation lead to several technical challenges for microgrid protection design. Protection methodologies can be categorized as current-based, voltage-based, impedance-based, differential-based, or adaptive.

3.1 Traditional protection principles

The conventional power grid design for distribution networks features a radial configuration with unidirectional power flow from generation to load. Two main protection measurements are voltage and current. Fault current level depends on the type of generation sources, load location, network configuration and impedance [14]. In a traditional grid, the fault current from ground faults can be several times greater than the normal load current. The main protection devices for a traditional protection solution are nondirectional current-based relays to detect overcurrent (OC) and earth fault (EF) conditions. Detection time assumes a fault current characteristic, which is the magnitude and speed of the fault current response, that considers the electromagnetic coupling of synchronous generators to the network frequency.

The traditional current-based relay settings come from short-circuit fault currents that could exist in worst-case scenarios for loading and generation conditions. In a unidirectional radial system, the high current limit would usually be found by taking the three-phase short circuit current level at the beginning of the feeder to represent the highest expected fault current. The two-phase short circuit at the end of the feeder is usually the lower limit. The maximum load current is also considered because relays should not send tripping signals during normal loading conditions. In radial networks with unidirectional power flow the fault location can be found from the fault type and short-circuit current level because it is directly related to line impedance [21].

OC relays are simple and widely used protection devices. A common way to express OC operation is through a time-current curve, which describes the operation time in relation to pick-up current. The time multiplier setting (TMS) is on the x axis expressed logarithmically and the relay pickup current (Ip) is on the y axis logarithmically. The pick-up current value establishes at what fault current magnitude the relay initiates a breaker trip. Time settings in OC relays are often inverse time; in this case the time delay is inversely proportional close to the pick-up value but has a constant time delay for large current values. Time settings and current settings are carefully set to discriminate which relay should pick-up the fault, as shown in Fig. 3.

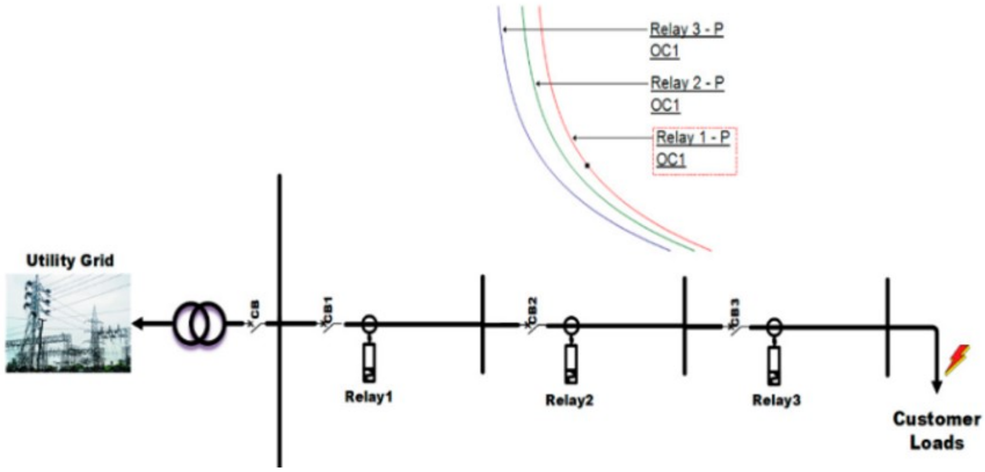


Figure 3. *OC relay coordination in radial feeder [5]*

Coordination is the main design challenge for OC relays along a radial feeder. Adequate coordination is called selectivity. OC relays need to be selective to guarantee that the correct faulted feeder is isolated and cleared. Time delay settings give a selectivity interval to discriminate between protection zones. For example, in the case of a radial feeder with unidirectional power flow the relay closest to the supply would have the highest time lag to separate the response zones. For a fault that happens at the end of the feeder, the closest relay compared to the fault detects and sends the tripping signal which minimizes the outage area.

The advantages of OC protection are that it is simple, reliable, fast, and relatively inexpensive. The main disadvantage is that outside of the traditional radial configuration it is extremely hard to coordinate the operation of non-directional OC relays which results in blinding and sympathetic tripping [5].

3.2 Fault current

Short-circuit faults create unwanted low impedance paths that can lead to excessively high fault currents. Insulation failure, which could come from equipment degradation, temperature, or extreme weather conditions, introduces this low impedance path that could exist between phases and/or ground. There are also high impedance faults, which are not discussed in this thesis.

Fault current is often the primary measurement for fault detection. The magnitude and duration of fault current contributions in microgrids will largely determine most OC protection system designs. For SG, the decaying fault current characteristic is defined in time periods of sub transient, transient, and steady-state period. Fault current contributions are studied using short-circuit analysis and are indicators of grid strength. Short-circuit analysis is used to see if electrical equipment is sized appropriately as to mitigate damage from high short-circuit currents. Fault currents can cause overheating, fire danger, and mechanical damage to the power system. The objectives of short-circuit current calculations are to help a protection strategy detect, clear, and reduce the consequences of faults.

Faults can either be symmetrical or asymmetrical. The two symmetrical faults, three-phase-to-earth (LLLG) and three-phase-fault (LLL) are uncommon but the most severe. Most faults will be asymmetrical; the fault current occurs at different magnitudes and angles for each phase. The asymmetrical faults are singe-phase-to-earth (LG), phase-to-phase (LL) and two-phase-to-earth (LLG). The LG fault is the most common.

Symmetrical component theory is used to analyse power systems under unbalanced conditions. In symmetrical faults, such as the LLLG fault, the fault current can be represented by the positive sequence equivalent circuit. In the case of asymmetrical faults, there will be positive sequence current, negative sequence current, and possibly zero sequence current circulating through the system. Microgrid short-circuit analysis for protection studies considers the main fault current, SG fault current, IIDG fault current, and grounding scheme.

3.2.1 Synchronous generation fault current

From the microgrid perspective, the main grid connection can be modelled as a large synchronous machine with Thevenin equivalent grid impedance. Main grid fault current will supply positive, negative, and possibly zero sequence current. The zero sequence current contribution depends on the grounding scheme. In normal steady-state operation, the current supply from an SG depends on the load impedance seen from the generator terminals. At the fault point, the generator terminals suddenly see a low impedance. In response the current flowing in the armature winding increases. The generator increases the current output. Total fault current is limited by the internal impedance of the generator and the line impedance path to the fault point. Fig. 4 shows the short-circuit symmetrical and asymmetrical SG fault current contributions.

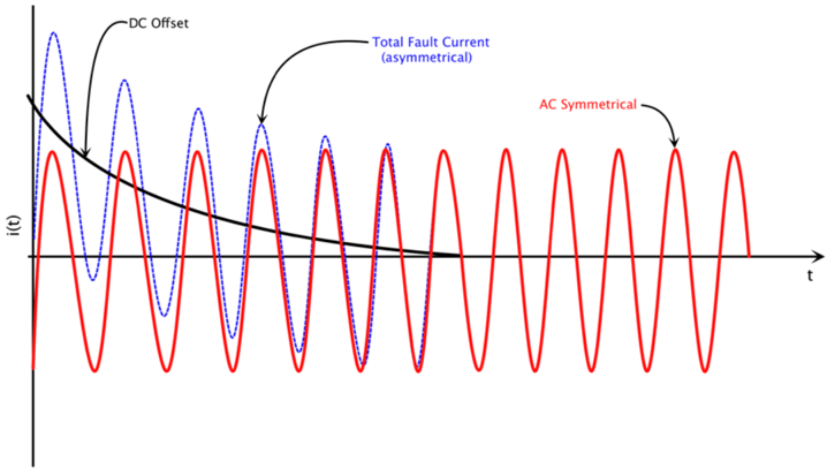


Figure 4. *Short-circuit asymmetrical current from SG [22]*

Fault current contains DC and AC components as shown in Fig. 4. There is a symmetrical contribution to the fault current as shown in the figure but there is also an unsymmetrical contribution which is the DC offset. The decay of the DC offset depends on the resistance and reactance in the magnetizing and damping windings. SG provides fault current with a magnitude of several times greater than the rated current for a sustained amount of time. For this reason, fault current can be a simple indicator for fault detection in OC protection strategies [14].

3.2.2 Inverter-connected generation fault current

IIDG does not contribute fault current in the same way as SG. The way IIDG contributes fault current depends on the control scheme. In the case of voltage-controlled schemes in the dq frame, the current is not directly controlled. Instead, the current regulator is part of the inner control loop. During a fault, measured voltage drops. In response, the current regulators will adjust by increasing current to meet the active and reactive power references. An important dilemma for inverters is the current limitations of highly sensitive switching devices. Maximum converter current ratings limit the fault contribution to around 2 pu of rated inverter current. The maximum current depends on source type, control, and design, but IIDG connections can bring fault current levels to as low as 1.2 - 1.5 of rated load current [15].

Another consideration is the fault current composition that the inverter supplies. In the study of faults, an unbalanced fault current can be represented by positive, negative, and zero sequence symmetrical components. IIDG usually lacks a grounding path, resulting in an absence of zero sequence current. In most designs, a VSI will only contribute positive sequence and negative sequence fault current.

Another consideration is the dimensioning of microgrids. Microgrids are flexible and can operate in a variety of load and generation scenarios. In some hours for Category 2 microgrids, power could be almost entirely supplied from inverter-connected resources. Levels of fault current depend on the generation level of DER, which is often intermittent and stochastic. This is a problem when the inverter is a dominant generation source for the microgrid because during a fault there would not be a noticeable OC event; fault currents are incredibly close to rated load current, and the traditional protection scheme would not detect the fault. The intermittency of generation requires a protection scheme that can detect faults regardless of the generation scenario.

It is also important for IIDG resources to remain online during disturbances. IIDG are more sensitive to voltage and frequency deviations than SG. IIDG have sensitive power electronic devices and lack inertia. In contrast, SG can provide inertia and withstand stronger voltage and frequency events. Most grid connections require that IIDG follows fault ride through (FRT) standards such as Fig. 5.

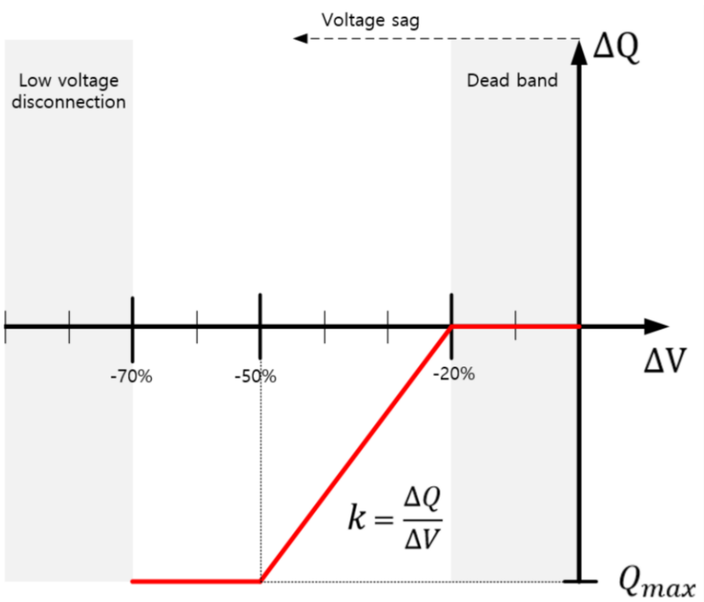


Figure 5. *Example low voltage fault ride through requirement [21]*

Low voltage FRT dictates the type of network conditions the inverter must continue to remain online and sometimes supply reactive power; these requirements are defined by a voltage-time characteristic. The FRT requirements will influence the fault current contribution because it details how long the inverter must supply current before it is allowed to trip.

3.2.3 Grounding methods and fault current

Unbalanced faults contribute negative and zero sequence currents. The selection of grounding devices and their configuration impacts the fault response and corresponding protection coordination. Zero sequence current is blocked by delta or floating wye winding connections of the transformer and the generators. The grounding selection of the main grid, DER transformer, and inverter will influence the fault current contribution. If the grounding is not designed appropriately, a possible consequence is voltage rise, called back feed. A grounding solution comes by making a trade-off between getting the smallest voltage rise possible and a high enough fault current contribution for the protection scheme.

The selection of the DER transformer connection will have a great impact on the zero sequence currents. The DER interface transformer selection is commonly Yg/Δ or Yg/Yg. The selection of a Yg/Δ transformer will block zero sequence contribution from the DER. Blocking the zero-sequence current path reduces fault current levels which challenges OC protection schemes that rely on a high fault current response.

A real concern for the integration of an IIDG to the grid is the lack of grounding for inverter-connected devices. Most VSIs are not designed to include a zero sequence current path. There are options for the inverter to include a zero sequence current path, for example by adding a grounding between the split capacitors on the DC link or by adding a fourth leg. These options are expensive and not regularly seen in the industry. A future possibility could be that inverter-connected devices are required to contribute zero sequence current because of the protection challenges associated with large-scale renewable microgrids.

3.3 Microgrid protection challenges

The conventional OC protection solution often fails to accurately detect and respond to microgrid faults. The size and location of DG production in a network will influence the magnitude and direction of the fault current, possibly causing OC protection failure [6]. Microgrid protection must successfully operate despite the challenges of blinding, sympathetic tripping, two operational modes, and IIDG.

3.3.1 Blinding

The presence of intermittent DG sources implies that the fault current magnitude will vary depending on the temporary renewable generation level. Traditional OC protection relays rely on fixed values for time and current pick-up settings. As DG integration increases, one possible consequence to OC protection relays is blinding. Blinding occurs when an OC protection relay measures a smaller fault current than the pick-up value. Fig. 6 shows the blinding zone where the OC relay would fail to detect the fault condition.

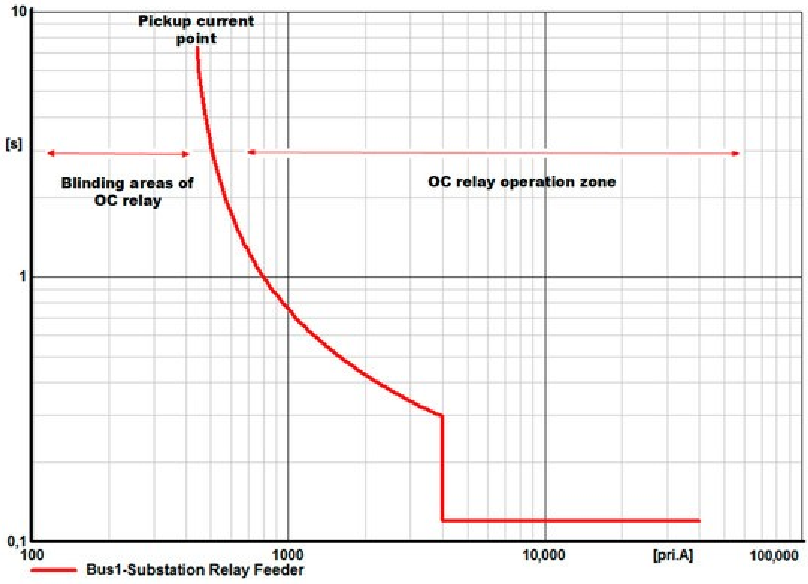


Figure 6. *Overcurrent (OC) relay operation characteristic curve [5]*

In the blinding zone, the relay will not trip because the fault current is smaller than the pick-up current. The result is that the OC relay is blinded to the disturbance and no protection actions are taken. An undetected fault in the network can cause system damage, overheating, and fire danger. Blinding is most likely to happen when there is a large DG unit far away from the substation and the fault happens close to the DG unit. Fig. 7 shows the blinding zone where the OC relay would fail to detect the fault condition.

The location of DER also influences the fault magnitude. Fault current rises near the DER installation and is less noticeable farther away. The fault current level is dependent on the impedance, and therefore distance, between DERs and fault location [14]. These variations explain why relay protection settings cannot function from a fixed value for networks with high renewable penetration. Relay operating regions need to adjust to changes in fault current magnitude and direction [6].

3.3.2 Sympathetic tripping

A microgrid is largely characterized by the presence of DG along the feeder. In this design, there is now multi-directional power flow occurring. A consequence of bidirectional power flow is the sympathetic tripping of a healthy feeder. Sympathetic tripping means that the OC protection relay falsely detects a fault situation in a healthy network. Fig. 7 shows an example network diagram where sympathetic tripping could occur.

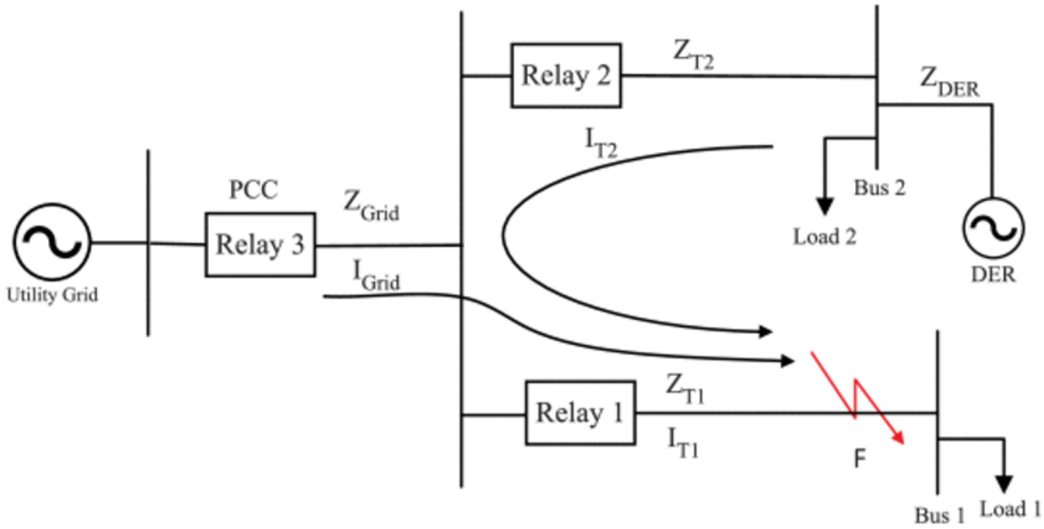


Figure 7. *Example of sympathetic tripping [3]*

Sympathetic tripping occurs most frequently during adjacent feeder faults. The DER unit will supply fault current through the bus bar to the adjacent feeder. As a result, both feeders see a fault situation due to the high current levels, despite only one of the feeders truly experiencing the fault. Both OC relays initiate breaker tripping, and more customers than necessary experience the power system disturbance. This lowers system reliability because a healthy feeder experiences an outage. Sympathetic tripping is likely to happen in the case of a large DG unit and a fault point close to the substation [5]. The solution to sympathetic tripping is to install a directional OC relay that can sense the correct scenario and therefore can differentiate between a healthy and faulty feeder. A directional OC relay adds the criteria that the fault current must also be coming from the correct direction to discriminate between the situations.

3.3.3 Two operational modes

Microgrid protection schemes need to operate for both grid-connected and islanded modes. The protection problems associated with two operational modes include different fault current levels, loss-of-mains protection, and re-synchronization. Fault current level changes depending on the operational mode. While operating in grid-connected mode, in general, most of the fault current comes from the utility grid. In islanded mode, the fault current level is lower because only the DERs are adding to the fault current. Therefore, it is necessary to change the settings depending on what mode the microgrid is operating in [14].

There are other reasons to be concerned with the main grid connection. Islanding occurs when the microgrid is disconnected from the main grid and loads remain energized by local DG units [23]. In the circumstance of islanding, the microgrid must detect this condition through loss-of-mains protection. Loss-of-mains protection is important because accidental islanding can lead to safety risks for personnel and extreme voltage and frequency deviations. Detection is important and should be quick, precise, and cost-effective [23]. Islanding detection requires local monitoring of system parameters such as voltage, current, impedance, power, and frequency. Effective islanding detection recognizes and isolates from the main grid through the PCC within a few seconds [14]. Resynchronization is necessary to reconnect the microgrid to the main utility grid with the correct system frequency. The protection studies of this thesis are focused on protection for internal low impedance microgrid faults, not loss-of-mains and synchronization challenges.

3.4 Inverter-interfaced generation

Protection approaches often develop based on the amount and duration of fault current generated by production units. Synchronous and inverter-connected DG's produce different levels of fault current due to differences in their electromagnetic characteristics. There is a concern about the proportion of inverter-based DERs to SG-based DERs and how that affects the fault current level [24]. Small fault current contributions lead to OC relays not sensing a fault condition. Protection can also be influenced by new levels of harmonics present in the system. High frequency power electronics used in inverters introduce harmonics that can lead to false tripping [6].

Traditional OC protection still has the possibility of succeeding for microgrids, but the differences in fault current between operational modes requires an adaptive protection scheme that changes OC relay settings depending on islanded or grid-connected mode. It may also be necessary to place compensation devices in the system to limit the threat of protection malfunction from harmonics.

In the situation of an 100% inverter-based system, a complete absence of SG will have an impact on the protection scheme. During a fault, the current would only come from the inverters which naturally cannot provide the same fault current levels as SG. One solution to the low fault current levels is to oversize the inverters to produce more short-circuit current of up to 3 - 5 pu [25].

3.5 Microgrid protection methods

The factors of bidirectional power flow, intermittent generation, mode of operation changes, and DER connection cause technical protection challenges for microgrids. New protection strategies are therefore necessary to handle the more dynamic fault currents seen in microgrid power systems [14]. The main protection approaches for microgrids are current-based, voltage-based, impedance-based, differential current-based, or adaptive. These protection solutions are for Category 2 microgrids with SG still present in the network.

3.5.1 Current-based

OC protection is the most widely used method for distribution systems, but the applications for microgrids become challenging due to coordination, selectivity, and sensitivity difficulties as previously described. Current-based detection adapts to the traditional solution by changing the relay settings or the relay type. Adjusting time delays and pick-up current settings can avoid blinding zones up to a certain point. As more DG is added, the coordination between relays becomes increasingly challenging. Adding a fault current limiter (FCL) to the DG connection can allow the traditional methods to work by limiting the fault current supplied from DG, which would eliminate the problem of sympathetic tripping. A FCL gives low impedance in normal operation but gives high impedance during a fault. This can restore the coordination of traditional OC protection relays [3]. The main concern with FCL protection is the high investment cost and difficulties in practical implementation [27]. Directional OC is seen in looped networks to detect bidirectional power flow and prevent sympathetic tripping.

3.5.2 Voltage-based

Voltage-based detection measures under voltage, over voltage, under frequency and over frequency. During a fault, voltage levels will usually dip and possibly become unbalanced. One voltage-based approach is to transform three-phase voltages to the dq reference frame and monitor positive sequence voltages to identify faults [28]. A disadvantage of this method is that it cannot detect high impedance faults (HIF) and is susceptible to errors because of regular voltage drops that occur in a grid [5]. Differentiating between faulty and normal conditions, along with determining fault location, is challenging for voltage-based detection.

3.5.3 Impedance-based

In distance protection, the impedance measurement is the fault-detecting parameter. Distance, also known as impedance-based detection, works by estimating the fault impedance from the measured short-circuit current and voltage. The estimated impedance is then compared to a set threshold which will identify a fault situation. An advantage of this method is that it works for both grid-connected and islanded microgrid operational modes [28]. A challenge for this method is measurement error because microgrids generally have shorter lines which lower the accuracy of distance protection [21].

3.5.4 Differential

Differential protection is often considered to be the best microgrid protection technique. The strategy works by monitoring the electrical quantities entering and exiting the protection zone. A differential relay measures the differential of five current parameters: zero sequence, negative sequence, phase one, phase two, and phase three [14]. Variations in the parameters indicate a system disturbance. The method of differential protection is shown in Fig. 8.

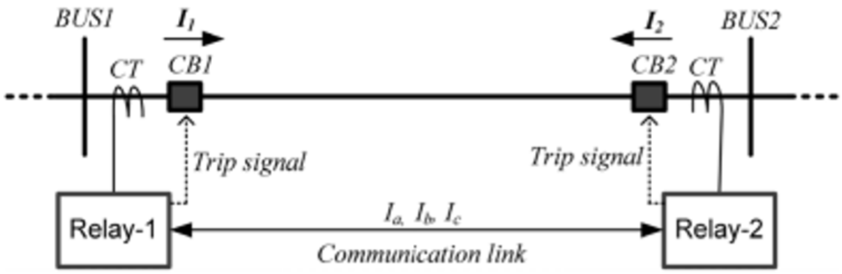


Figure 8. *Differential protection [33]*

This protection strategy is simple, good for HIF detection, and highly sensitive. Differential protection is not influenced by lower fault current levels that are expected in microgrids with high amounts of IIDG. Another advantage is that differential protection is unaffected by bidirectional power flow [33]. The main disadvantage is that it is more expensive than other protection methods and it often adds an extra element of a communication link. Communication within a protection scheme introduces another point of failure.

3.5.5 Adaptive

Adaptive relay techniques have emerged as a promising solution for microgrid protection. Adaptive methods can function with any relay type. The main idea for the adaptive OC approach is to update pickup current levels by adapting to the network situation [6]. This requires an online system and communication that can manage relay settings that could be set under the OC, differential, or symmetrical component strategy [21]. One adaptive approach uses a central protection unit to store all the fault types and location scenarios for every microgrid configuration and can direct the tripping signals based on the network state. The drawback of adaptive protection is that it requires a costly communication infrastructure. Additionally, any lapse in communication is now an extra point of failure for the protection system which lowers reliability. A decentralized approach uses IEC 61850 communication that publishes and subscribes messages between relays. The messages update the relay settings [15].

In addition to the traditional protection methods as previously described, innovative techniques that use machine learning, data mining, and wavelet transforms are also emerging in research [29]. Although these methods promise much, the main microgrid protection practical implementations are overcurrent-based and differential protection. As described, traditional OC methods tend to fail as renewable power contribution grows in proportion to SG generation.

3.6 Microgrid protection studies

Comprehensive microgrid testing is necessary to ensure safe microgrid operation. Microgrids are designed using high frequency switching devices. Models that accurately show microgrid transient response need to have time-step solutions small enough to capture the switching behaviour. Often the solution is to do electromagnetic transient (EMT) studies.

Source [30] investigated the coordination of directional OC relays in networks with embedded DG using EMT simulation. The system had two CHP generators of 3 MW capacity. To do the protection system analysis, short-circuit current levels were tracked either with DG or without DG. The system revealed the limitations of OC protection by showing the cause and case of sympathetic tripping due to DGs installed in the network. The system showed the increase in short-circuit current levels that came from the increased DG production. The time-current curves showed the protection coordination and why it needed to be adjusted.

There have also been studies about 100% inverter-based microgrids. Several studies have been done to test the control and protection schemes for microgrids with 100% inverter-based resources. Control and protection strategies depend according to the topology, generation source, and microgrid operating conditions. In [31], a completely inverter-based microgrid with three solar PV units was tested using adaptive protection. The inverters operated in grid-following mode and provided rated or set-point real power to the grid. In islanding conditions, all inverters transitioned to grid-forming control. The control was based on droop characteristic curves. Another study modelled and validated a system with three-phase paralleled VSI. The control strategy was a modified virtual inertia PID droop-control and virtual impedance. The result was fast and accurate power sharing for the inverters and good system stability for frequency and voltage. The testing was done using hardware in the loop (HIL) [32]. In [25], a microgrid with 100% renewable capacity was modelled including a grid-forming BESS. The primary control method was droop control. System events of faults, generation loss, and load swing were simulated using the software model; the result was stable operation.

4. TESTING ENVIRONMENT

EMT simulation is used to test and verify protection schemes with small time-step solutions that can accurately show the high frequency switching circuits seen in microgrids. Microgrids benefit from protection testing and verification because of the variety of microgrid approaches and the cost of protection failure. Power electronic simulations require high frequency switching to correctly represent the behaviour of pulse width modulation (PWM) control. This thesis designs and tests a microgrid with SG and IIDG to show protection principles. In this chapter, the microgrid model and testing use cases are described.

4.1 Microgrid network model

The test system is an MV grid-connected microgrid with one inverter-connected DG and one synchronous DG as shown in Fig. 9.

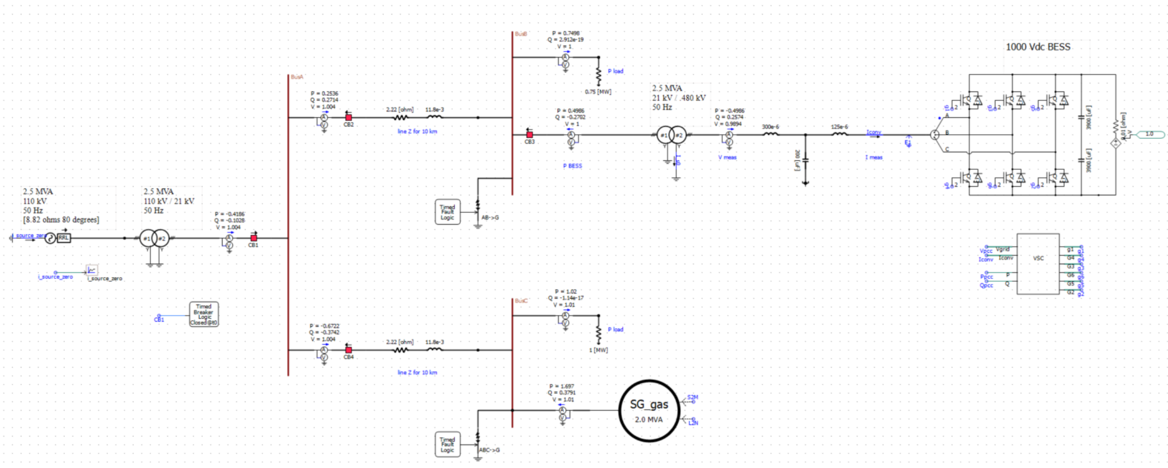


Figure 9. *PSCAD single line diagram of microgrid model*

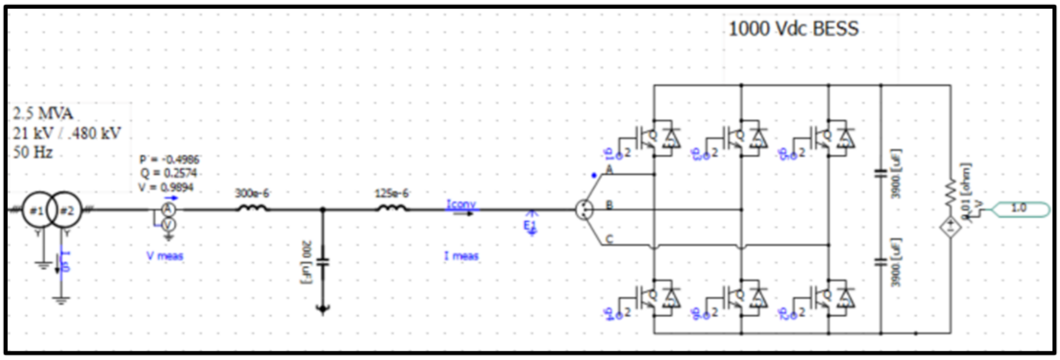
Two feeders are coming from the main grid, each with a DG and resistive load. The first feeder has a 1 kV BESS that is connected through a Yg/Yg transformer which steps up the voltage from 480 V to 21 kV. The transformer connection was selected as Yg/Yg to provide grounding for maximum fault currents because the application of this microgrid is for protection studies. The microgrid frequency is 50 Hz. The main grid connection is modelled by a three-phase 21 kV source with an impedance of 8.82 Ω. Each feeder has a line impedance of 2.2 + j3.7 Ω and the line lengths are 10 km. The entirely resistive loads are 0.75 MW for feeder one and 1 MW for feeder two. The BESS is controlled as a PQ grid-following inverter; the BESS operates according to active and reactive power set points. For islanded mode, the SG has voltage and frequency control. The model for the SG was provided by the second examiner, doctoral student Lasse Peltonen. The microgrid parameters are listed in Table 1.

***Table 1**. Microgrid parameters*

Parameter	Rating
Voltage	21 kV
Frequency	50 Hz
Base power	2.5 MVA
Base current	68.73 A
Load 1	0.75 MW
Load 2	1 MW
Feeder impedance	2.2 + j3.7 Ω
Feeder resistance	2.2 Ω
Feeder inductance	11.8 mH
Source impedance	8.82 Ω 80 degrees
Source voltage	110 kV
BESS rated power	1.182 MW
BESS DC voltage	1 kV
BESS switching frequency	8 kHz
Grid-side LCL filter inductance	125 μH
Inverter-side LCL filter inductance	300 μH
LCL filter capacitance	200 μF

4.2 Grid-following VSI model

The objective of an inverter is to change a DC input into an AC output at a certain voltage magnitude and frequency. VSI are either voltage-controlled or current-controlled. VSI set points can come from active power, reactive power, power factor, or DC voltage references. Regulation can occur in the dq0, αβ, or abc reference frame. A VSI can be grid-forming or grid-following. Fig. 10 shows the inverter model created in PSCAD.



Transformer LCL filter IGBT three leg inverter

Figure 10. *PSCAD diagram of the inverter model*

The BESS is modelled as a 1 kV constant voltage source with a VSI. A two-level, three-phase voltage source inverter converts the 1 kV DC source to a 480 L-L Vrms AC source. The VSI is voltage-controlled, and the set points are supplying 0.5 MW active and supplying 0.25 MW reactive power. The IGBT switching devices have current limitations of 4 A for the id and iq control components. The switching frequency of the IGBTs is 8 kHz. The switching of the IGBT circuit injects a correction voltage into the microgrid to bring it to the active and reactive power set points. The control output will synthesize a three-phase voltage of the best predicted voltage amplitude and phase to adjust the power flow to the set points. The inverter output waveform is sent through an LCL filter to reduce harmonics. The control strategy implemented in PSCAD is shown in Fig. 11.

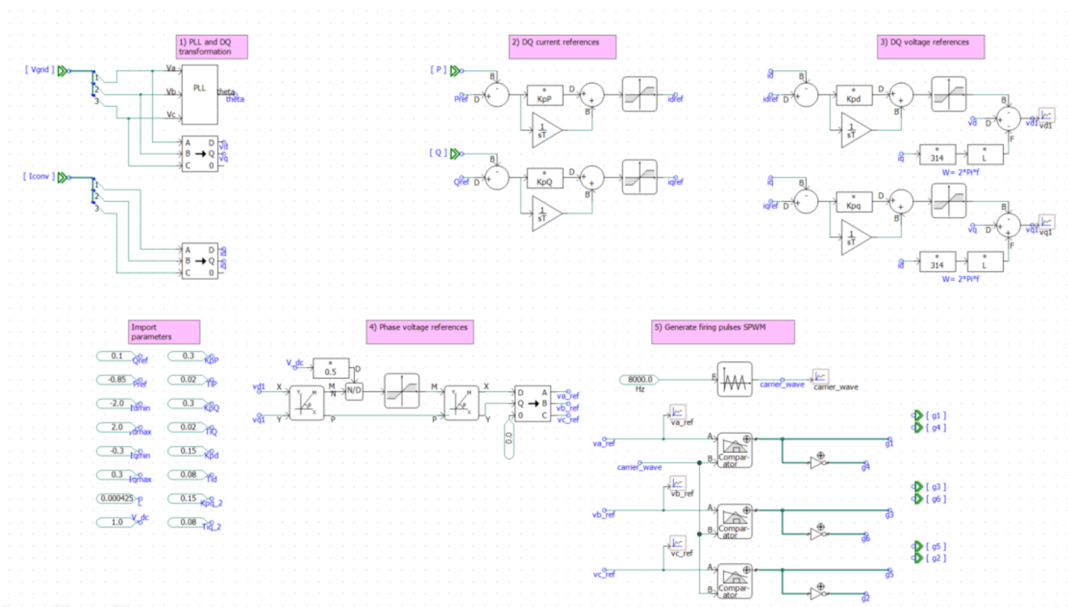


Figure 11. *PQ grid-following control VSI*

A grid-following inverter detects the network phase and frequency through a PLL. The current measurements were taken after the filter at the inverter connection point. Then the PCC voltages and currents were transformed into the dq0 reference frame using the Clarke-Park transformation.

Current control is often done in a rotating reference frame. To convert AC sinusoidal power to a two-phase rotating reference frame, there are two transformations. The first is the Clarke transformation that converts a three-phase signal to a two-phase alpha beta reference frame. Next is the Park transformation that converts a two-phase stationary frame to a two-phase rotating frame. In this view, the current signals in steady state are now DC signals defined by the direct (d) and quadrature (q) components. An advantage of DC signals is that they are easier to filter and regulate using PI controllers.

Next, a controller regulates the active and reactive power output to the set point using simple proportional integrator (PI) controllers. The most common control algorithm used is the PI controller. A PI controller will calculate the error value between the desired set point and the actual signal. Next, the controller will minimize the error between the values. The inverter control tracks the active and reactive power references by adjusting the current reference. The inner loop regulates the current output, and the outer loop regulates the power output. Limitations are placed on these PI controllers because of the sensitivity to the switching devices. Active power is controlled using the id component and reactive power is controlled using the iq component. The d and q frames are decoupled by subtracting the opposite terms at the end of the control loop. This operation is part of step 3 in Fig.11.

The output of the PI control loops gives a reference voltage that can be synthesized and injected into the microgrid using PWM. The PWM operation is shown in Fig. 12.

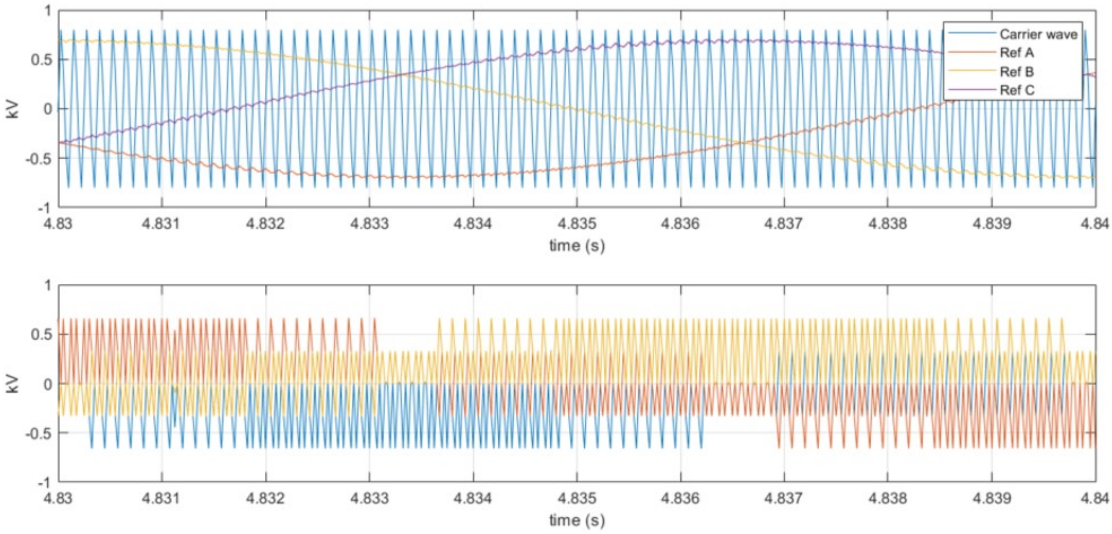


Figure 12. *PWM carrier wave and reference voltages*

The switching of the IGBTs occurs at 8 kHz. The PWM technique compares sinusoidal signals with a triangular wave to determine the firing pulses for the IGBTs. The IGBTs are activated when the triangle wave is less than the sinusoidal wave. These firing pulses will synthesize a voltage source that can be used by the control to adjust power flow.

4.3 Microgrid simulation use cases

Power electronics often operate at much higher switching frequencies than the grid frequency. To accurately measure the system dynamics, it is important to have a modelling solution capable of small time-step simulations to capture power electronic behaviour. EMT studies are important to show how the higher switching frequencies will affect microgrid stability, protection, and power quality for a range of connection and loading scenarios.

The time-step size for the simulations is 5 μs. The simulations are designed to demonstrate protection considerations for microgrids with SG and IIDG. Inverter switching behaviour should be accurately modelled using EMT simulation to correctly show the way an inverter would respond to fault situations. Case study one shows the microgrid fault response in grid-connected mode. Case study two shows the microgrid fault response in island mode. Fig. 13 shows the microgrid configuration and the fault locations.

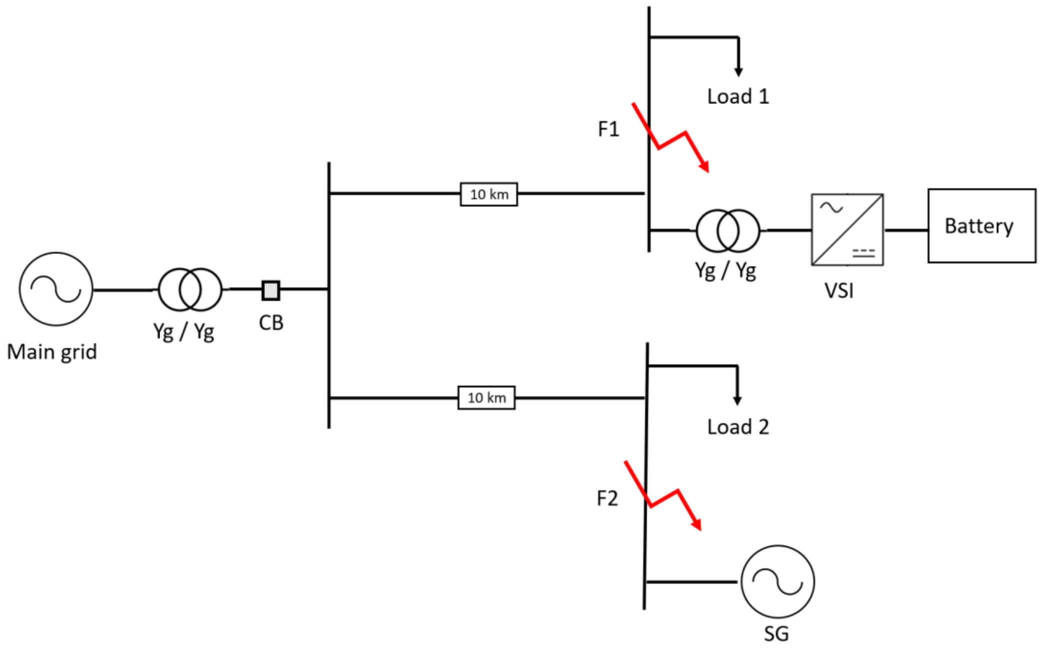


Figure 13. *Case study microgrid and fault locations*

The objectives of the PSCAD simulations are to:

- Show how generation sources supply fault current (main grid, BESS, SG)
- Demonstrate the transient response differences between grid-connected mode and island mode
- Demonstrate the transient response differences between fault types
- Demonstrate the transient response differences between fault locations

The following fault types are simulated: LG fault, LL fault, LLG fault, LLL fault, and LLG fault. Fault location 1 is near the BESS and fault location 2 is near the SG. A fault resistance of 1.1 Ω was selected to provide higher fault currents for the protection studies. The fault was initiated at t = 5 s with a duration of 0.2 s.

4.4 Case study one: grid-connected mode

The purpose of case study one is to show the differences in fault current contributions between the main grid, SG, and BESS. The voltage, current, and inverter control response are analysed to study the transient fault response. This study shows the difference in the grid-connected microgrid response to different fault types and fault locations.

4.5 Case study two: island mode

The purpose of case study two is to show the differences in fault transient response for the microgrid in islanded mode. At the time of t = 2 sec, the microgrid is islanded. The voltage, current, and inverter control response are analysed to study the transient fault response. This study shows the difference in the islanded microgrid response to different fault types and fault locations.

5. RESULTS OF CASE STUDY ONE: GRID-CONNECTED MODE

The purpose of case study one was to observe the microgrid fault transient response in grid-connected mode. The following fault types were tested: LG, LL, LLG, LLL, and LLLG. The fault resistance was the same in every simulation at 1.1 Ω. Voltage waveforms, current waveforms, and RMS fault current contributions were analysed for each test. The main grid measurement occurs at the PCC. The fault was initiated at t = 5 with a fault duration of 0.2 seconds.

5.1 Fault current contributions

Table 2 - 3 shows the peak RMS current contributions for each testing scenario.

***Table 2**. Fault current contributions at location 1*

	LG	**LL**	**LLG**	**LLL**	**LLLG**
Main grid (kA)	0.295	0.353	0.435	0.538	0.534
SG (kA)	0.0867	0.126	0.132	0.172	0.172
BESS (kA)	0.0241	0.0797	0.0615	0.0879	0.0851
Total (kA)	0.406	0.559	0.629	0.798	0.792

***Table 3.** Fault current contributions at location 2*

	LG	**LL**	**LLG**	**LLL**	**LLLG**
Main grid (kA)	0.307	0.378	0.450	0.555	0.548
SG (kA)	0.105	0.168	0.169	0.227	0.224
BESS (kA)	0.0219	0.0293	0.034	0.0633	0.0575
Total (kA)	0.435	0.575	0.653	0.846	0.829

The fault with the highest contribution is the LLL fault and the fault with the lowest contribution is the LG fault. In all cases, most of the fault current is supplied by the main grid. The BESS supplies the least amount of current. In the case of the LG fault, the BESS supplies no fault current because of the topology that restricts the zero sequence current contributions. Fault currents were slightly greater at location 2 where the fault was closer to the SG and farther from the BESS.

5.2 Effect of fault type

The LG and LLL faults are compared to observe how the microgrid responds to different fault types. The LG fault is asymmetrical and the most frequent. The LLL fault symmetrical and the most severe. To isolate the effect of fault type, the fault location was kept at location 1 for both tests.

5.2.1 Transient response to LG fault

Figs. 14 – 16 show the transient voltage and current for the microgrid during the LG fault.

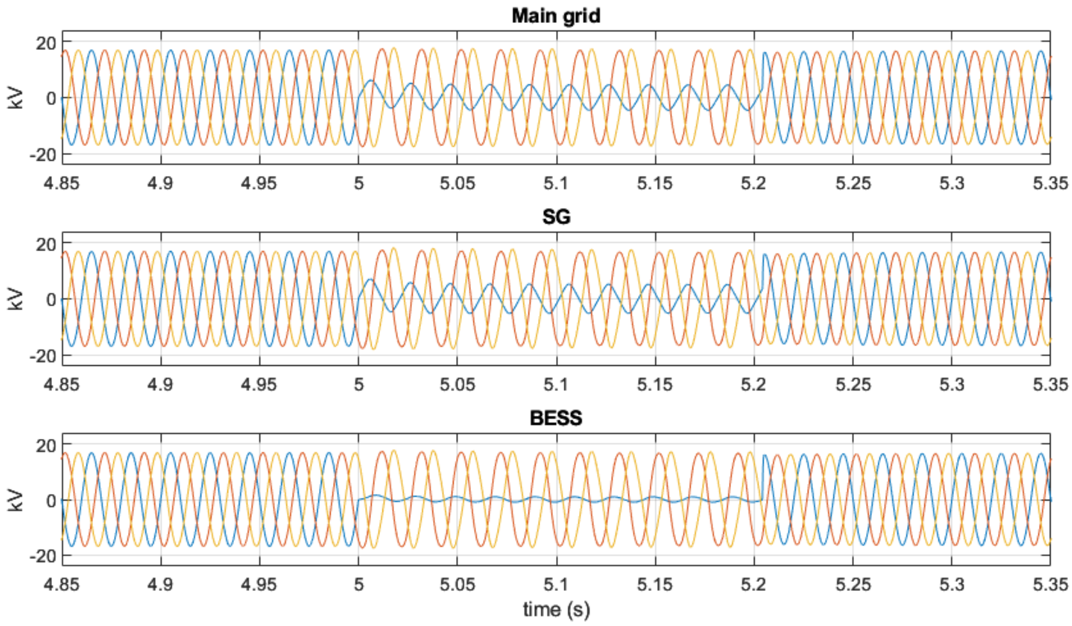


Figure 14. *Main grid, SG, and BESS voltage during LG fault*

The voltage drops on the faulted phase at every measurement location. The SG experiences less of a voltage dip on the phase because it is the farthest source from the fault point. The healthy voltage phases stay at the pre-fault voltage levels.

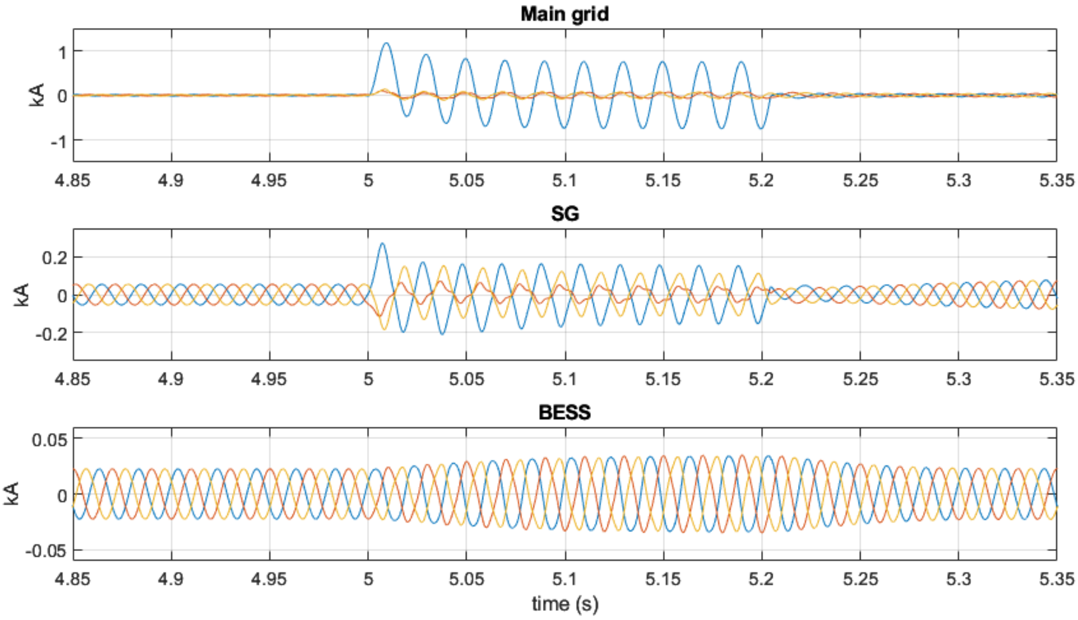


Figure 15. *Main grid, SG, and BESS current during LG fault*

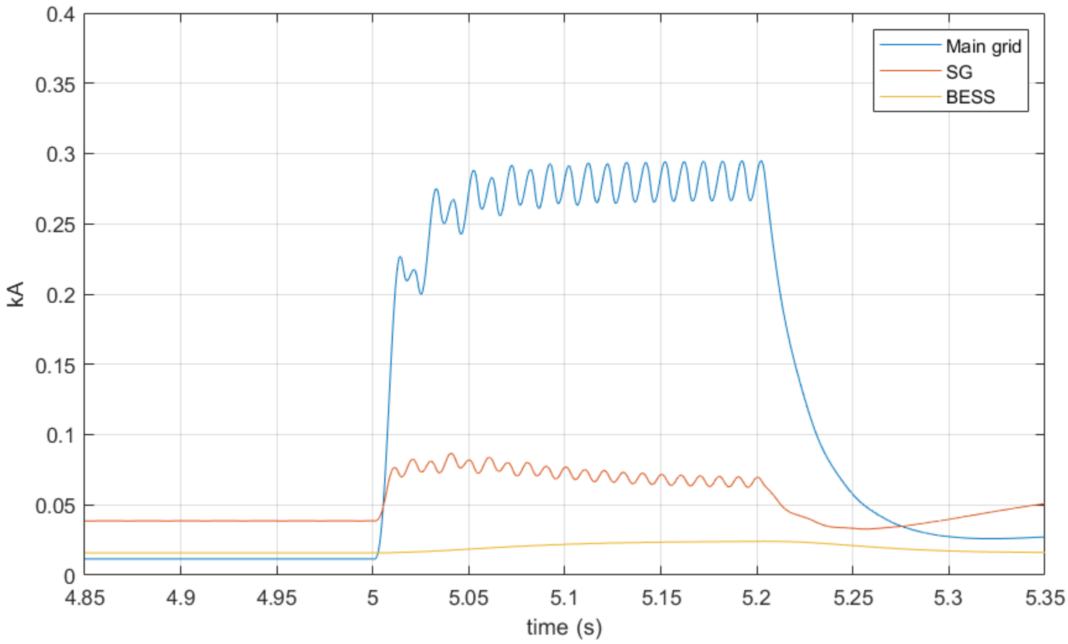


Figure 16. *RMS fault current contributions LG fault*

The main grid supplies a large fault current response on the faulted phase. Fault current contribution from the main grid depends on the Thevenin equivalent impedance of the grid connection. The SG follows the same fault current response characteristic as the main grid, but with a smaller magnitude. The SG provides some fault current on the non-faulted phases. The amount of fault current from the SG depends on the power rating and internal impedance. The BESS does not contribute fault current because it is an asymmetrical fault. For a BESS with no grounding, there will not be a path for the zero sequence current of the asymmetrical fault. The BESS has a small increase in output current, but this is due to the control response to the network dynamics.

5.2.2 Transient response to LLL fault

The next fault type studied was the LLL fault. The purpose is to compare the microgrid transient response of the LLL fault to the LG fault. The LLL fault is balanced and will more severely affect the microgrid. Figs. 17 – 19 show the transient voltage and current for the microgrid during the LLL fault.

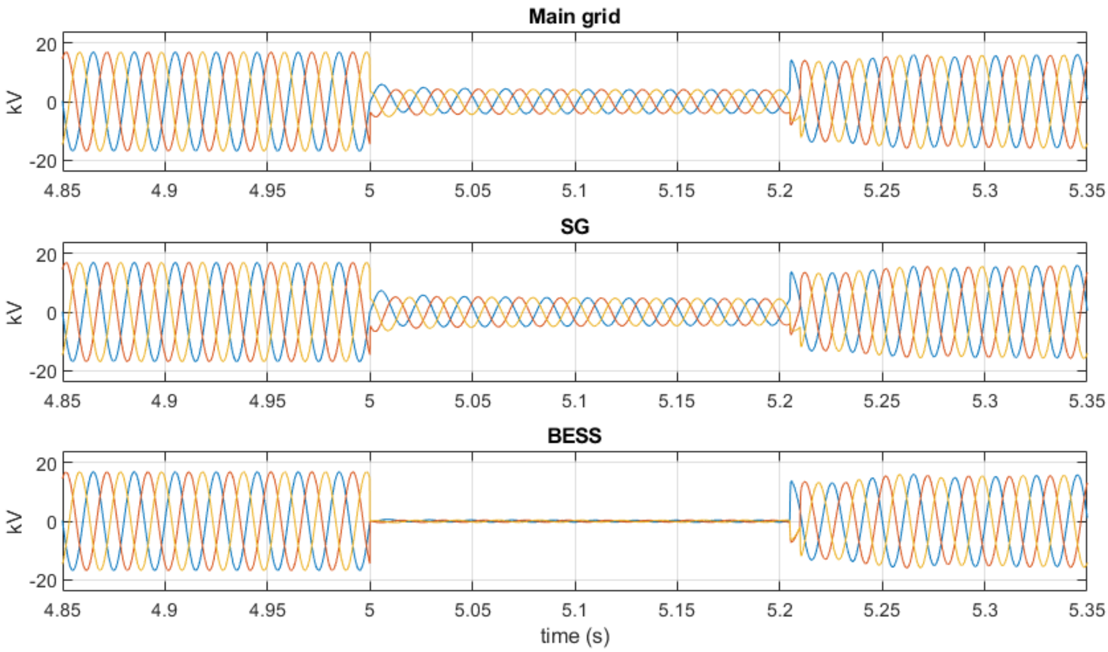


Figure 17. *Main grid, SG, and BESS voltage during LLL fault*

In the LLL fault, the voltage completely collapses at the BESS. The main grid and SG have a voltage drop to nearly 30% of the nominal voltage.

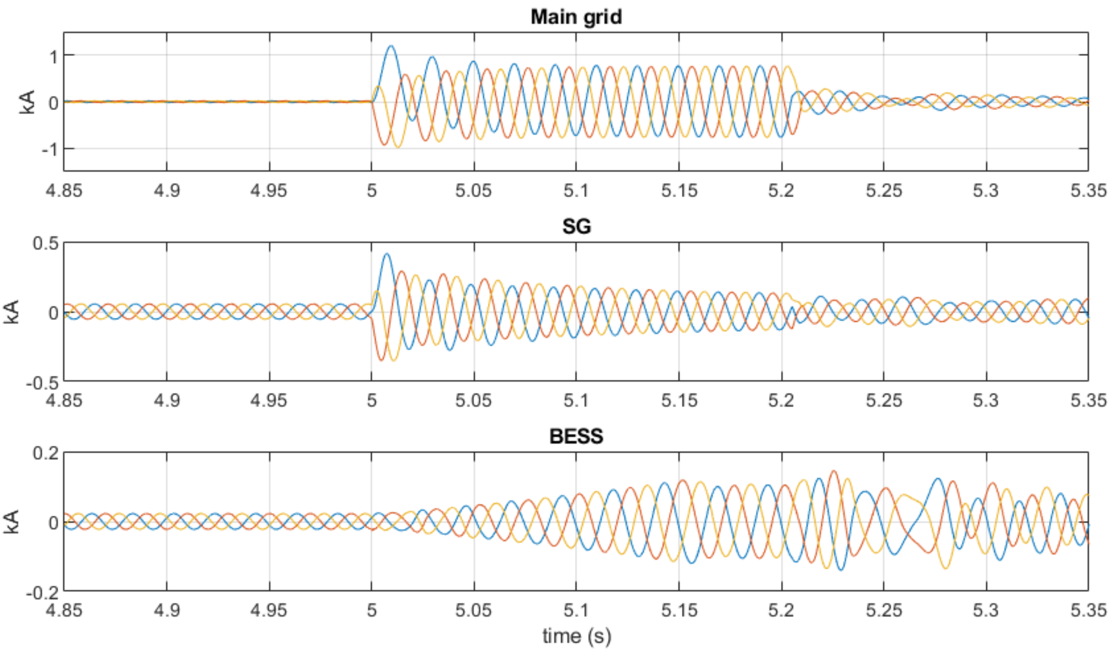


Figure 18. *Main grid, SG, and BESS current during LLL fault*

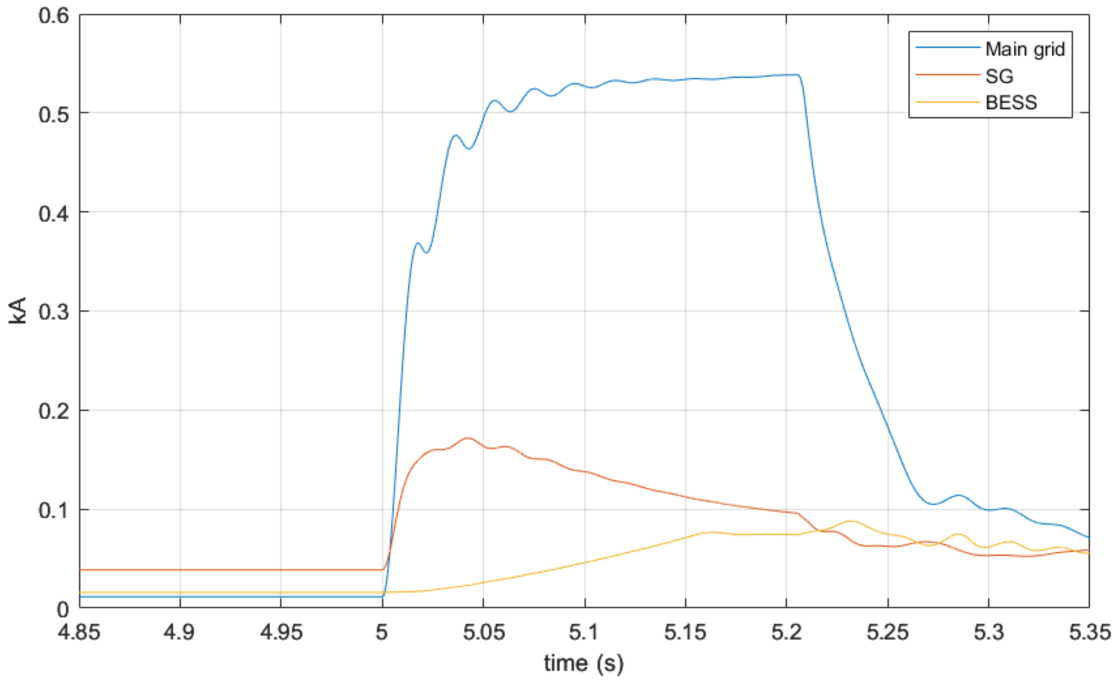


Figure 19. *RMS fault current contributions LLL fault*

All sources supply fault current in all phases. The fault current from the main grid is very large compared to the nominal load current. In contrast to the LG fault, the BESS can supply some fault current. The fault current coming from the BESS rises until the maximum current limitation is met; the gradual increase is most likely from the control logic. Fig. 20 compares the fault current contributions by source for both fault types.

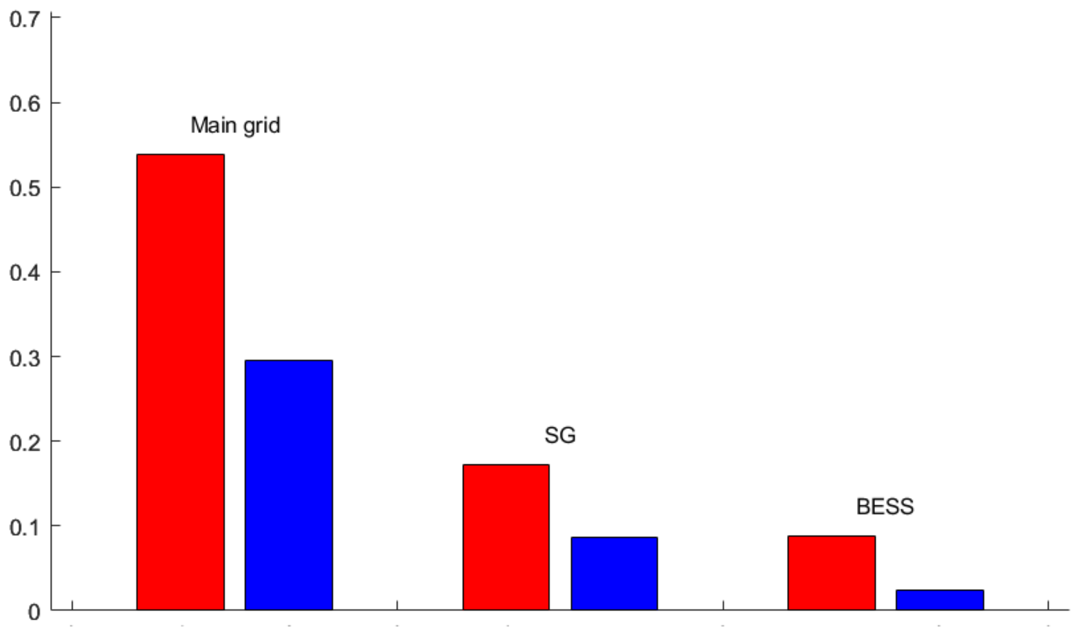


Figure 20. *Fault current comparisons LLL and LG fault*

The LLL fault, shown in red, is the most severe microgrid fault. The LG fault contributions are shown in blue. The main grid supplies most of the fault current with SG as the second highest source. The least amount of contribution comes from the BESS, but the proportion of fault current is much stronger for the LLL than the LG fault due to the BESS topology.

5.3 Effect of fault location

Next, the influence of fault location is studied for the grid-connected microgrid. The transient response to a LL fault at feeder 1 is analysed and compared to a LL fault at feeder 2.

5.3.1 Transient response to LL fault at location 1

Figs. 21 – 23 show the transient voltage and current for the microgrid during the LL fault at location 1.

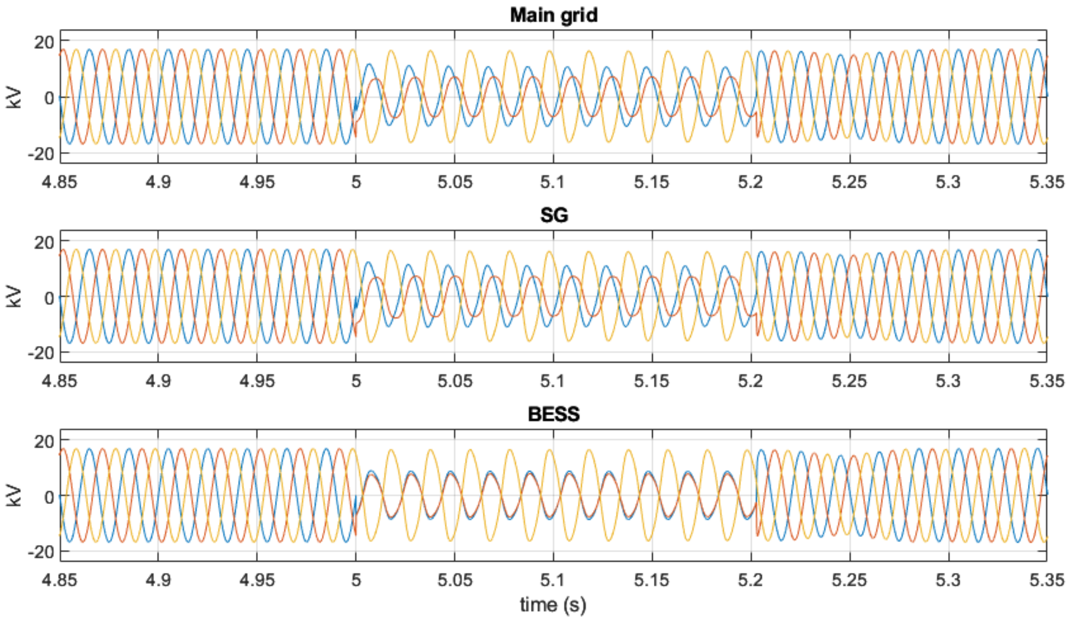


Figure 21. *Main grid, SG, and BESS voltage during LL fault at location 1*

For a LL fault, two phases contact each other and create an unwanted current path. The voltage drop is greater in the BESS waveform because the fault occurs at feeder 1 near the BESS. The SG, which is farther away from the fault, experiences less of a voltage drop.

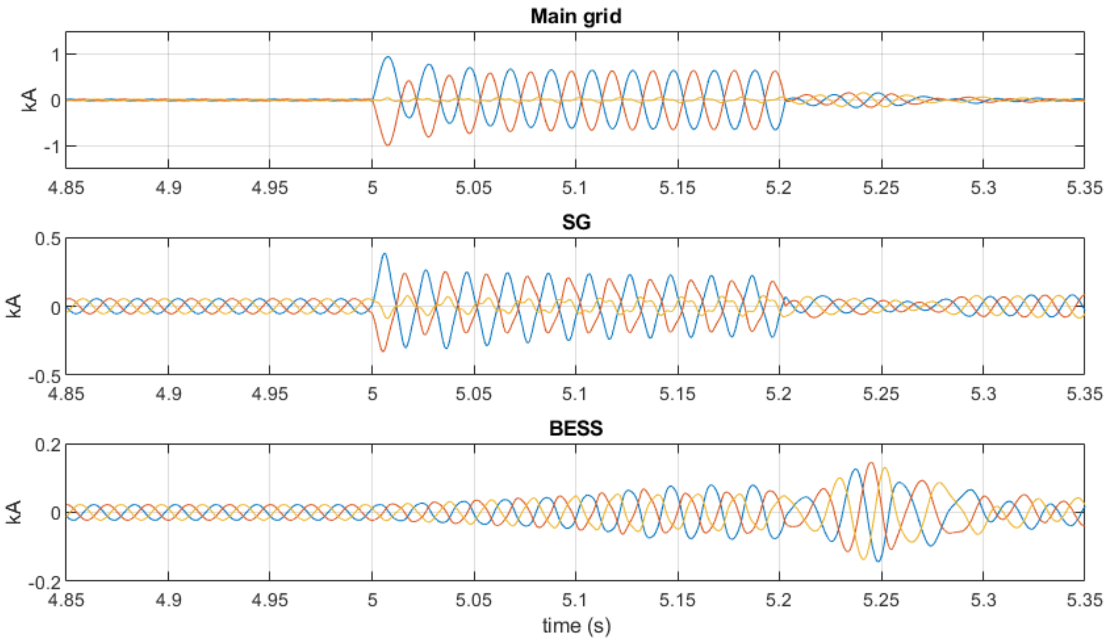


Figure 22. *Main grid, SG, and BESS current during LL fault at location 1*

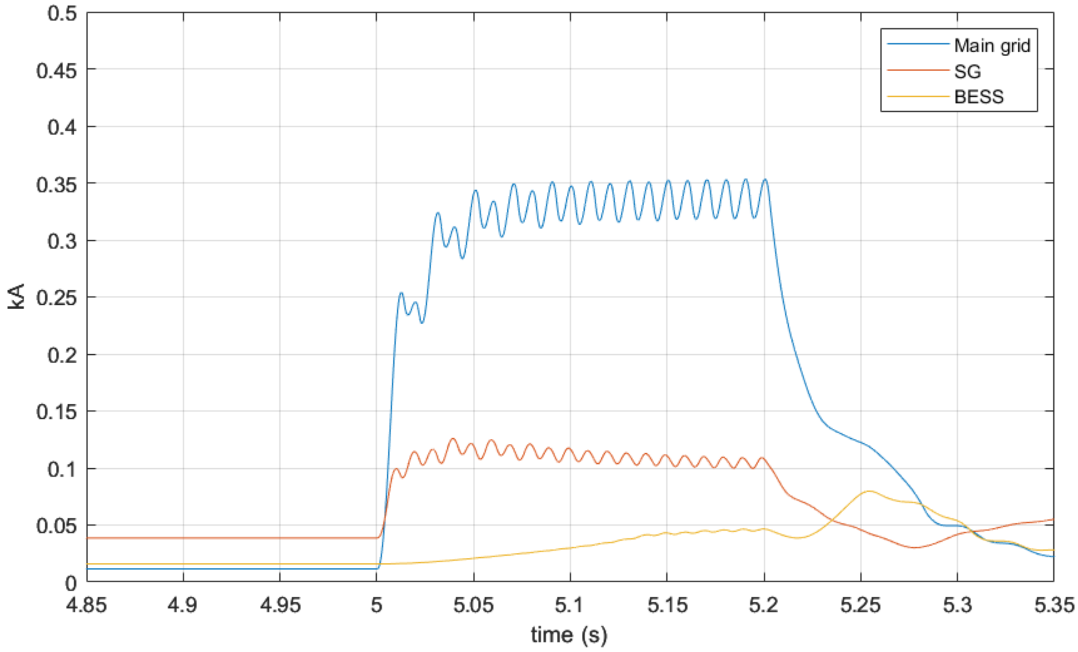


Figure 23. *RMS fault current contributions LL fault at location 1*

During the LL fault at location 1, the main grid and SG supply similar current responses but of different magnitudes. An LL fault is symmetrical, which allows the BESS to give more fault current contribution. Similar to the LLL fault, the control logic of the BESS gradually increases the fault current. After the fault is cleared at t = 5.2 s, the BESS further increases the current in response to the network dynamics. This current is not fault current; instead it comes from the control logic of the BESS while the microgrid adjusts back to steady-state conditions.

5.3.2 Transient response to LL fault at location 2

Figs. 24 – 26 show the transient voltage and current for the microgrid during the LL fault at location 2.

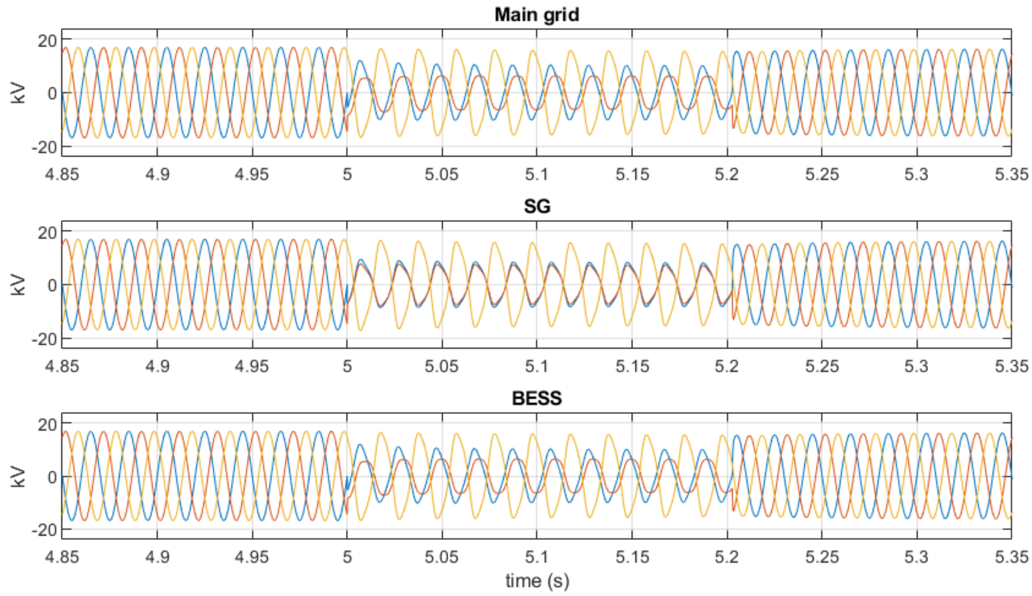


Figure 24. *Main grid, SG, and BESS voltage during LL fault at location 2*

For the LL fault at location 2, the SG experiences a higher voltage drop on the faulted phases. The main grid response is nearly the same for both locations. After the fault is cleared, the voltages appear balanced at every source connection. This is different than the post-fault voltages at location 1, which slightly increased before returning to steady-state values.

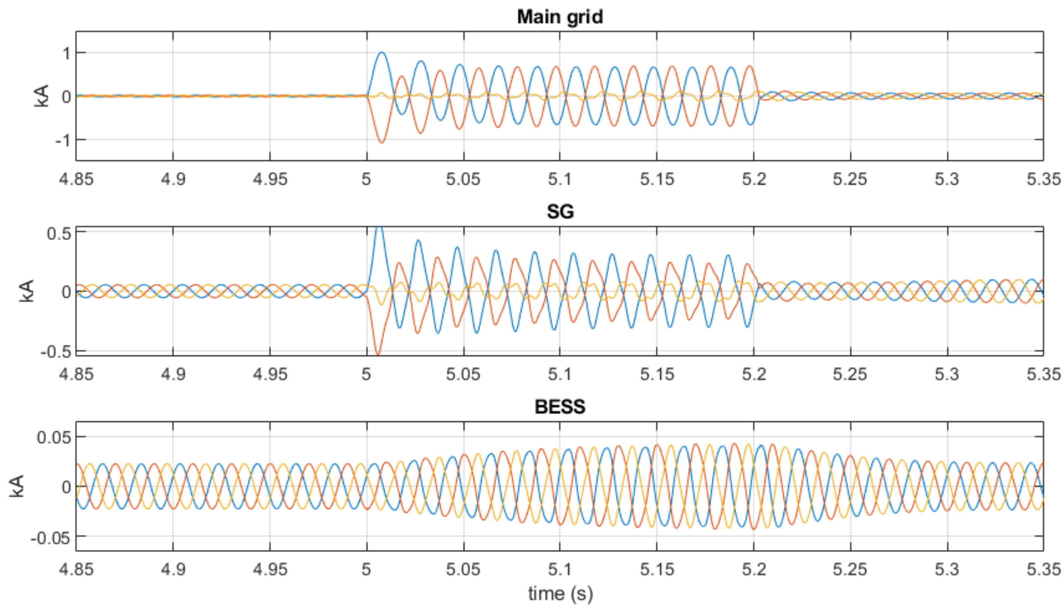


Figure 25. *Main grid, SG, and BESS current during LL fault at location 2*

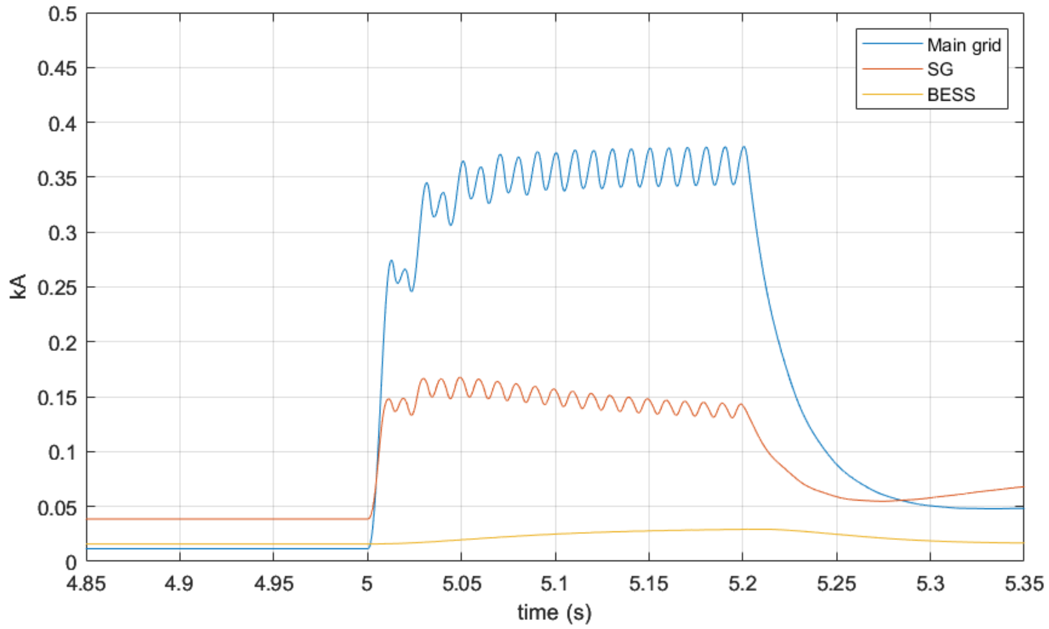


Figure 26. *RMS fault current contributions LL fault at location 2*

The main grid and SG gave similar fault current responses for both locations. In location 2, the BESS fault current response was different in shape. The BESS gave a gradual increase in fault current, and the waveform appeared balanced during and after the fault. The reason is likely connected to the BESS control response. For the fault farther away from the BESS, the control was more effective at responding to the rapid network dynamics. Fig. 27 compares the peak RMS fault current contributions between locations 1 and 2.

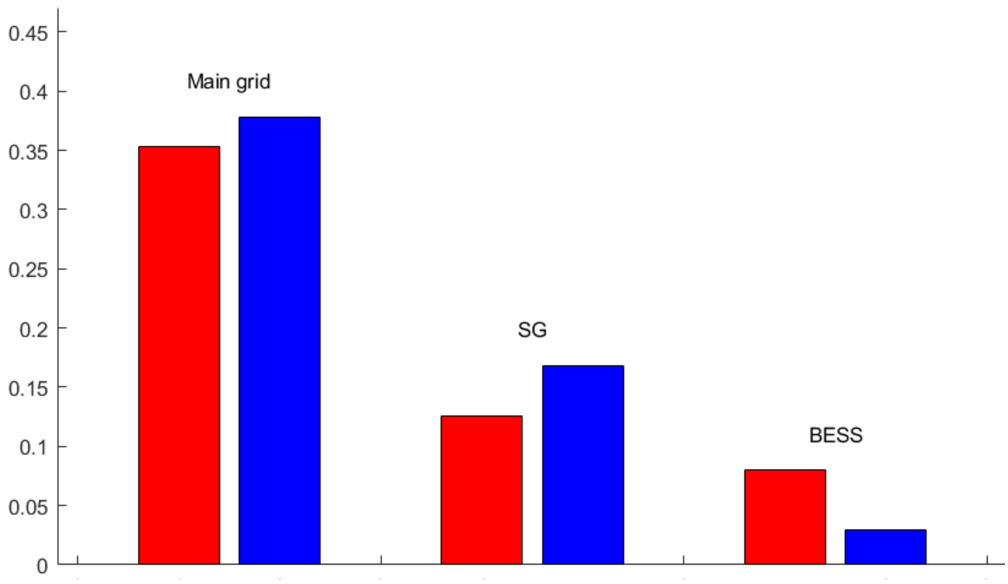


Figure 27. *Fault current comparisons for locations 1 and 2*

The red bars represent the location 1 fault currents, and the blue bars show the location 2. The total fault current levels are higher for location 2 faults. The composition of the total fault current also changes depending on the fault location. For a fault on the BESS feeder, the SG current is reduced because of the path through the line impedances on feeders 1 and 2. This lowers the overall fault current because more fault current comes from SG than the BESS. For the fault closer to the BESS, the BESS supplies more fault current.

6. RESULTS OF CASE STUDY TWO: ISLAND MODE

The purpose of case study two was to observe the microgrid fault transient response in island mode. The following fault types were tested: LG, LL, LLG, LLL, and LLLG. The fault resistance was the same in every simulation at 1.1 Ω. Voltage waveforms, current waveforms, and RMS fault current contributions were analysed for each test. In island mode, the SG is responsible for the voltage and frequency control. The BESS operates in grid-following mode. Islanding happens at t = 2 seconds to allow time for the microgrid model to reach steady-state. The fault was initiated at t = 5 seconds with a duration of 0.2 seconds.

6.1 Fault current contributions

Tables 4 - 5 show the peak RMS current contributions for each testing scenario.

Table 4. *Fault current contributions at location 1*

	LG	**LL**	**LLG**	**LLL**	**LLLG**
SG (kA)	0.0733	0.144	0.147	0.204	0.203
BESS (kA)	0.0186	0.0477	0.0659	0.080	0.079
Total (kA)	0.0919	0.192	0.212	0.284	0.282

Table 5*. Fault current contributions at location 2*

	LG	**LL**	**LLG**	**LLL**	**LLLG**
SG (kA)	0.0767	0.167	0.169	0.243	0.241
BESS (kA)	0.0182	0.0560	0.0532	0.0745	0.0737
Total (kA)	0.0949	0.223	0.222	0.318	0.314

The total fault current levels dropped significantly compared to the grid-connected mode. In the example of the LG fault, the total fault current drops from 405 A in grid-connected mode to 91.9 A in island mode. Fault current levels are greater at location 2.

6.2 Effect of fault type

The LG fault and the LLL fault are studied to observe the effect of fault type on the system transient response in islanded mode. To isolate the effect of fault type, the fault location was kept at location 1 for both tests.

6.2.1 Transient response to LG fault

Figs. 28 – 30 show the transient voltage and current for the islanded microgrid during the LG fault.

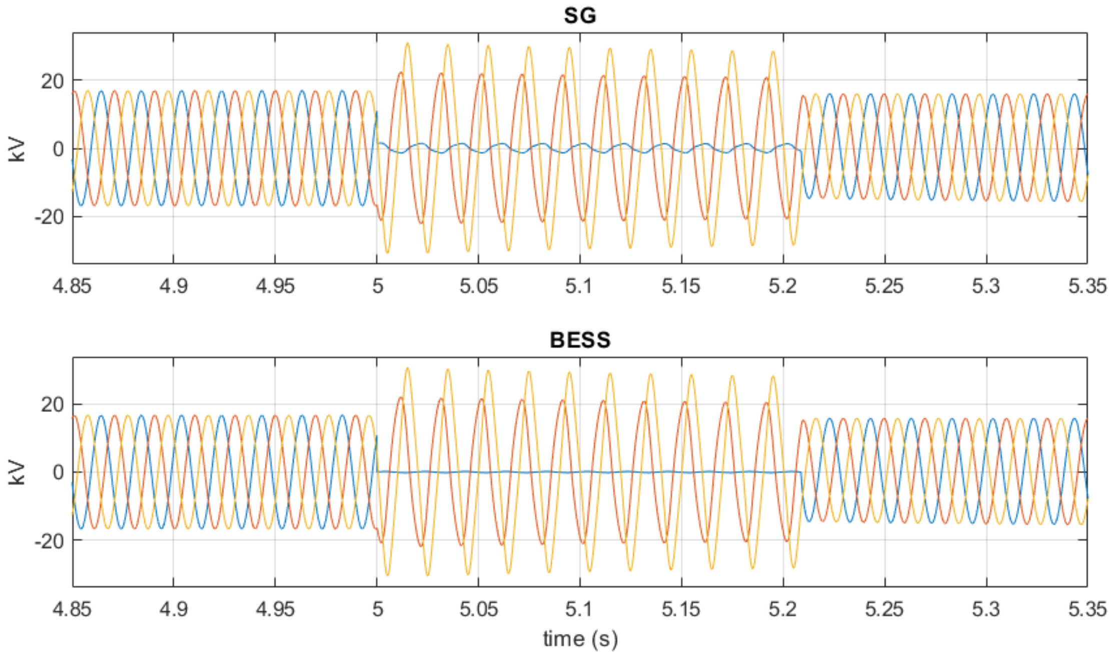


Figure 28. *SG and BESS voltage during LG fault*

At the time of the fault, the BESS experienced a larger drop in the faulted phase than the SG because it is closer to the fault point. The faulted phases in both DG drop very low, and the other two healthy phases experience voltage rise. The reason for the higher magnitude of the healthy phase voltages is unknown. The two healthy phases experience more voltage rise than in the grid-connected mode.

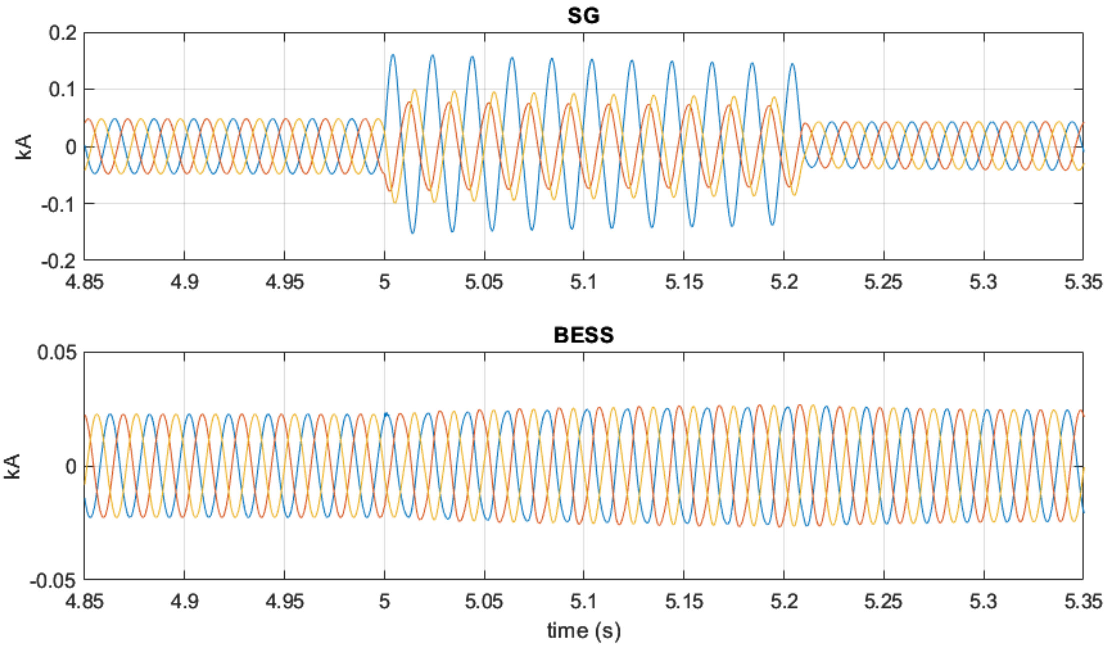


Figure 29. *SG and BESS current during LG fault*

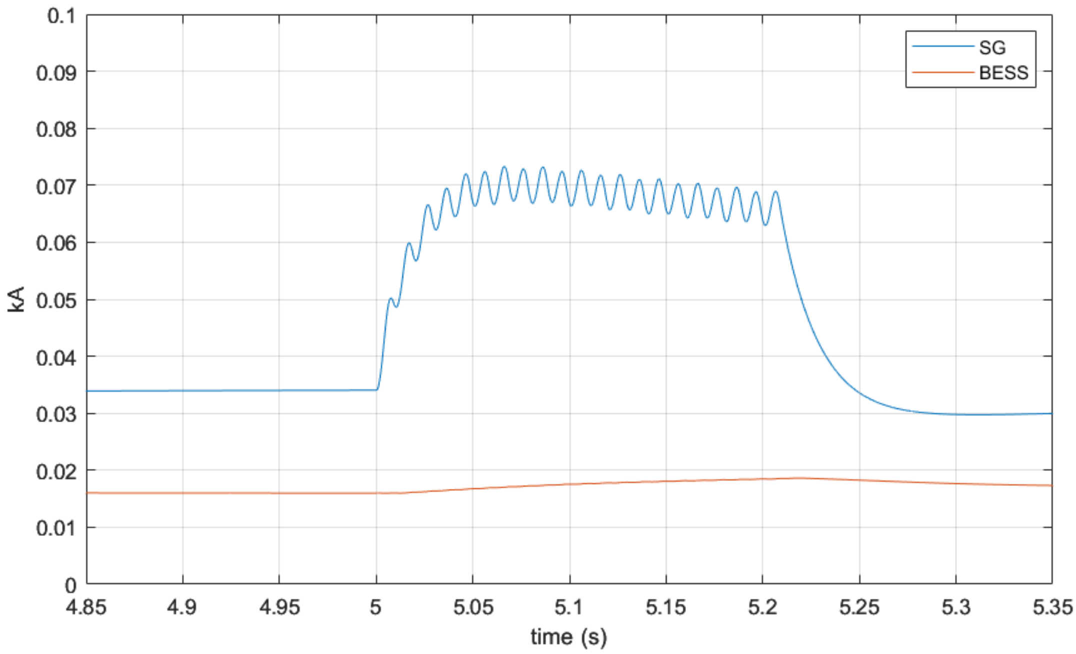


Figure 30. *RMS fault current contributions LG fault*

The SG supplied significant fault current on the faulted phase during the LG fault. There is more fault current in the healthy phases than in the grid-connected mode. There is no fault current from the BESS because it is an asymmetrical fault and there is no zero-sequence current path.

6.2.2 Transient response to LLL fault

The next test studied was the LLL fault. The purpose is to compare the microgrid transient response of the LLL fault compared to the LG fault. The LLL fault is balanced and will more severely affect the microgrid. Figs. 31 – 33 show the transient voltage and current for the microgrid during the LLL fault.

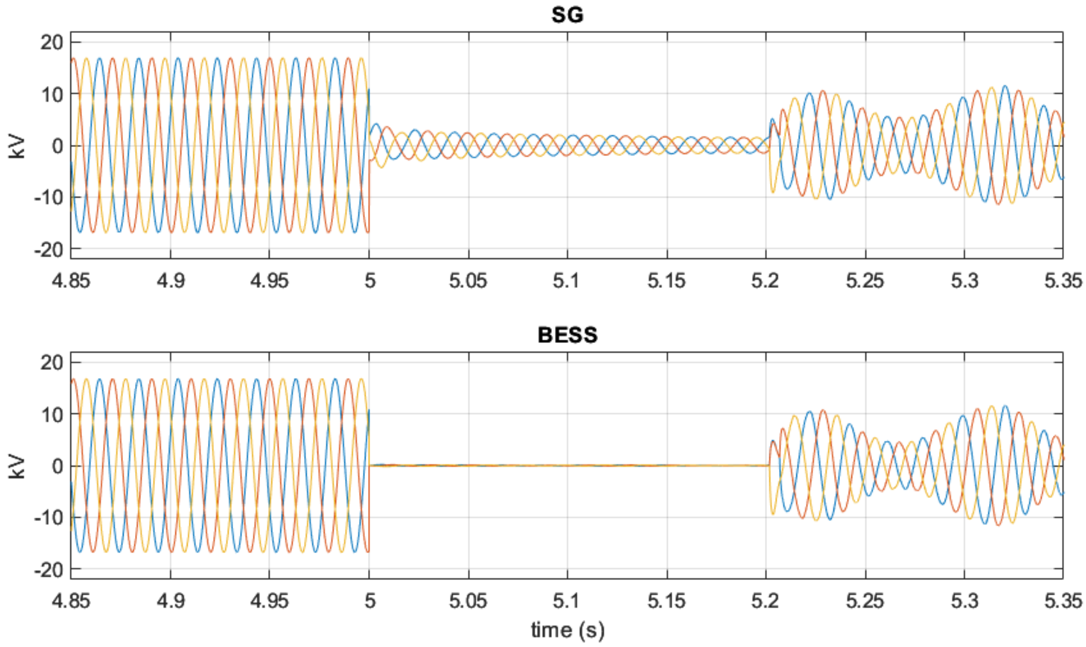


Figure 31. *SG and BESS voltage during LLL fault*

During the LLL fault, the voltage completely drops at the BESS measurement point. The SG voltage drops to around 15% of the nominal voltage. The LLL fault affects the network voltages more than in the grid-connected mode. After the fault is cleared, the voltages do not return to steady-state values and the system loses stability.

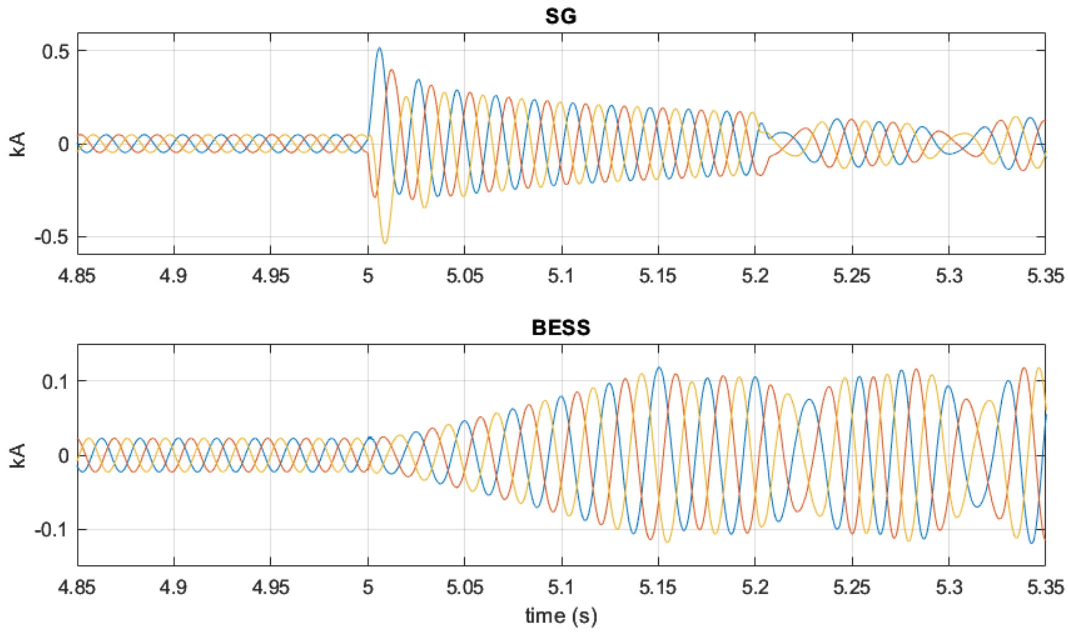


Figure 32. *SG and BESS current during LLL fault*

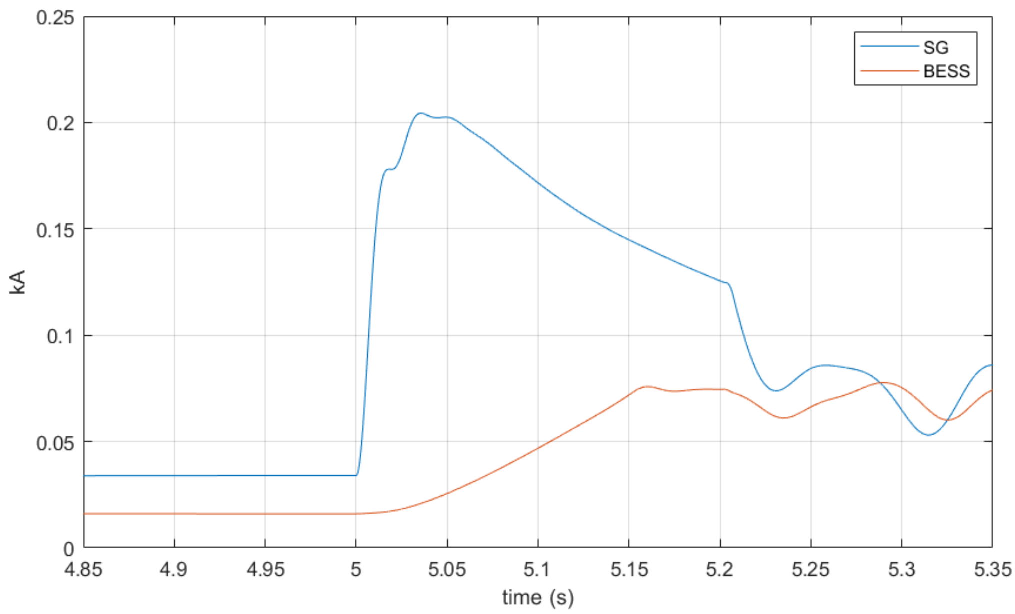


Figure 33. *RMS fault current contributions during LLL fault*

The SG provides a large amount of fault current immediately after the LLL fault. The BESS slowly increases fault current contribution until the maximum current limits of the control logic at t = 5.15 s. In islanded mode, the microgrid does not immediately find stability after the LLL fault is cleared. This is evident in the voltage and current waveforms. Fig. 34 provides a closer view of how the control system responds to the LLL fault in islanded mode.

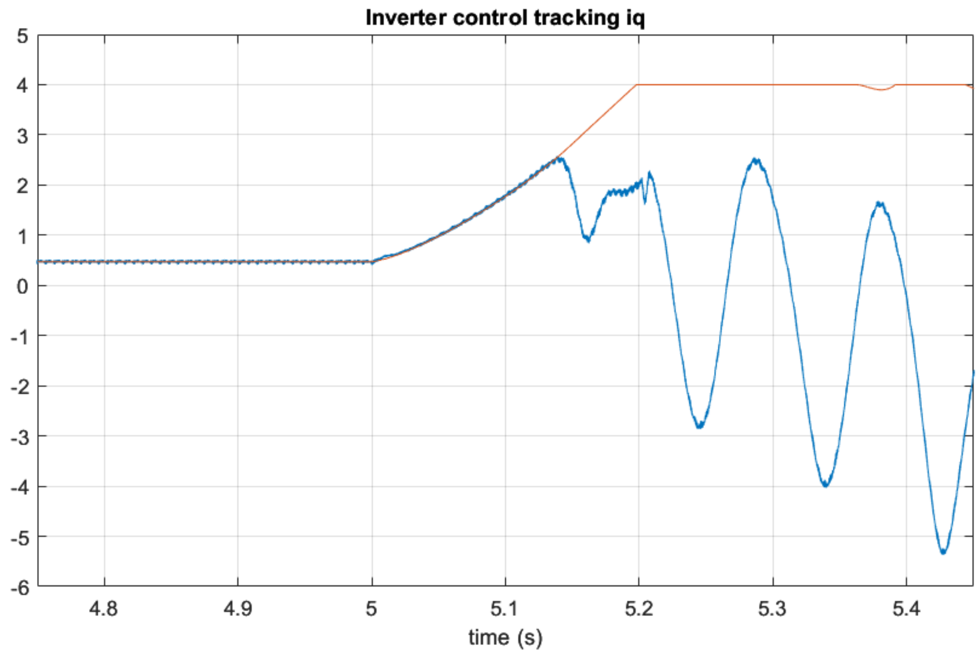


Figure 34. *BESS controller tracking iq component LLL fault*

At around t = 5.15 seconds, the iq component stops following the reference. The PLL stops tracking and the result is that the BESS cannot help with power flow adjustments. In this situation, the PLL loses the grid voltage phase angle. Eventually, the system regains stability but not until 2 seconds have passed since the fault was initiated. This is a common problem for abrupt load changes. If the PLL cannot properly track the grid voltage angle, then the injected power will not accurately follow the reference values. Fig. 35 displays the fault current contributions from each source for both fault scenarios.

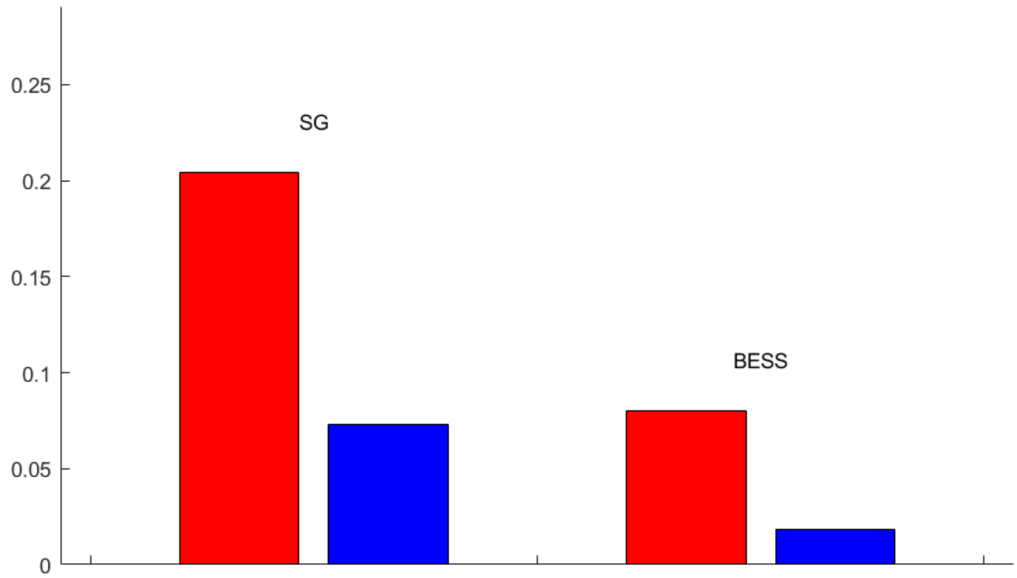


Figure 35. *Fault current comparisons LG and LLL fault*

The red bars show the fault current contributions during the LLL fault and the blue bars during the LG fault. In island mode, the SG supplies most of the fault current. Compared to grid-connected mode, the total fault current drops from 405 A to 91.9 A. This drop in fault current indicates a need for adaptive OC protection that can adjust the pick-up current settings based on the operational mode.

6.3 Effect of fault location

Next, the influence of fault location is studied for the islanded microgrid. The transient response to a LL fault at feeder 1 is analysed and compared to a LL fault at feeder 2. The voltage and current waveform transient response for the BESS and SG behave nearly the same as the grid-connected mode responses already analysed in Chapter 5. Fig. 36 compares the total peak RMS fault current contributions depending on the location.

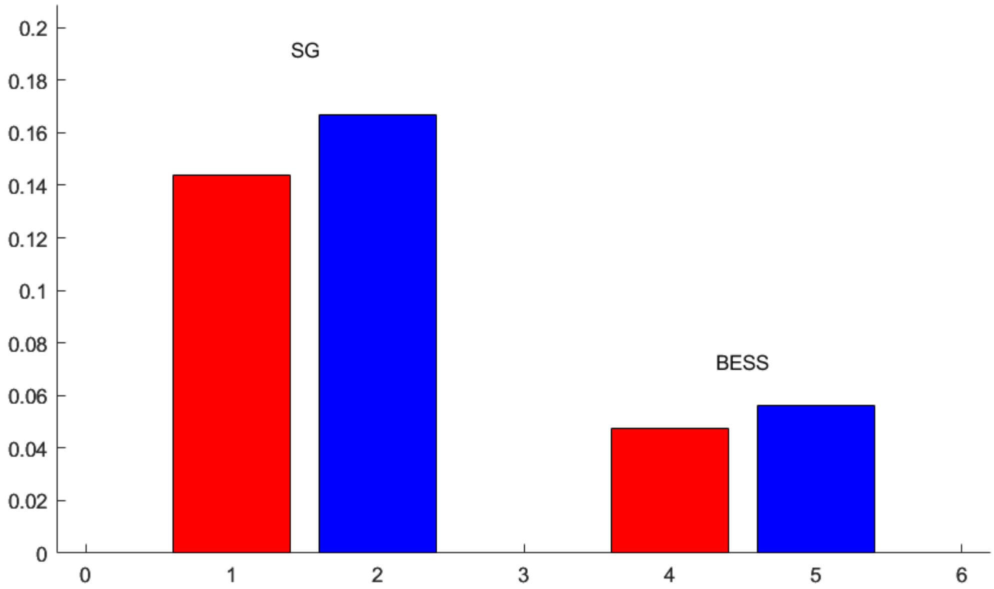


Figure 36. *Fault current comparisons between locations 1 and 2*

The red bars indicate the LL fault current contributions for location 1 and the blue bars for location 2. In both locations, most of the fault current is supplied by the SG. The network topology and fault location influence the impedance path the SG fault current flows through. The total fault current is greater for location 2 because of the shorter impedance path for the SG fault current. The higher level of BESS fault current in location 2 was unexpected. The BESS supplies more fault current in location 2 most likely because of the control response to the network dynamics. The islanded microgrid is more strongly affected by disturbances.

7. DISCUSSION

The purpose of this thesis was to demonstrate the protection design considerations for microgrids with IIDG. Testing the microgrid in two modes explained why traditional OC protection solutions are not always effective in microgrid applications.

This study could be improved upon by increasing the complexity of the microgrid model. Possibilities include more types of generation sources such as wind farms, solar power plants, and fuel cells. There could be a more complex topology with dynamic generation and load changes.

Controls could be enhanced by including MPPT for solar and wind power plants. In this microgrid, the inverter control is grid-following in both operational modes. A possible application could be using this microgrid to study entirely 100% inverter-based microgrid control strategies. This would require the inverter to sense the islanding situation and transition from grid-following to grid-forming control.

Another factor to consider is the fault-ride through. In many cases, large inverter-based generation is required to tolerate voltage and frequency situations to continue supporting the network during faults. This control was not included but could be an option to improve the study. It would show a more realistic response of inverter-connected resources.

Another option would be to change the grounding configuration and show the effect of blocked zero-sequence current on the fault current levels. Further, this microgrid model could be expanded to represent an adaptive OC protection scheme, where different OC values are set depending on the mode of operation and executed using CB components.

Another way to further this work is by transferring the model to a HIL testing environment. This would show the real-time nodal analysis for the entire system. HIL testing with relays would show the response times and selectivity. HIL testing is an industry standard and an increasingly important part of safe power system design.

8. CONCLUSION

This thesis simulated protection studies for microgrids with synchronous and inverter-connected generation. Microgrids operate in either grid-connected or stand-alone islanded mode. As the growth of renewable energy centred legislation and economic viability increases, it is expected that microgrids will be an enabling technology to integrate more renewable energy into the existing grid infrastructure.

Accurate microgrid modelling and simulations are an important part of testing and verifying protection strategies. There are many additional requirements for microgrid operation, but the primary thesis topic is about protection requirements and the consideration for microgrids with inverter-connected generation.

In this thesis, a microgrid is designed, modelled, and simulated with multiple DGs using PSCAD. Fault scenarios are simulated for the grid-connected mode and islanded mode of the microgrid. The testing showed that current contributions from the BESS depend mainly on its current limits, adapted control scheme, and topology.

Case one studied the microgrid in grid-connected mode. The dominant fault current contributor was the main grid for all faults tested. SG and IIDG supply fault current in different ways; the inverter-connected resource does not directly supply current, instead any current response happens from a high-bandwidth internal control loop. Additionally, the IIDG response is limited by the rating of the IGBTs. In the asymmetrical LG fault, the BESS is unable to supply fault current because of the grounding configuration which restricts the zero sequence current path.

Case two studied the microgrid in island mode. In island mode, the total fault current dropped significantly in comparison to case one. The testing showed that the sizing of OC protection schemes needs to change depending on the operational mode. Another result showed the tracking concerns of islanded microgrids for the severe LLL fault. The BESS control loses the PLL tracking during the LLL fault in islanded mode but not in grid-connected mode.

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